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Science Applications, Inc, La Jolla, Calif.

Prepared for

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ERDA U.S. Energy Research
and Development Administration
Fossil Energy
Washington, D.C. 20545

USBM U.S. Bureau of
Mines
Coal Preparation and Analysis Laboratory
Pittsburgh, Pennsylvania 15213

PROCEEDINGS OF THE ENGINEERING FOUNDATION CONFERENCE ON CLEAN COMBUSTION OF COAL

Interagency
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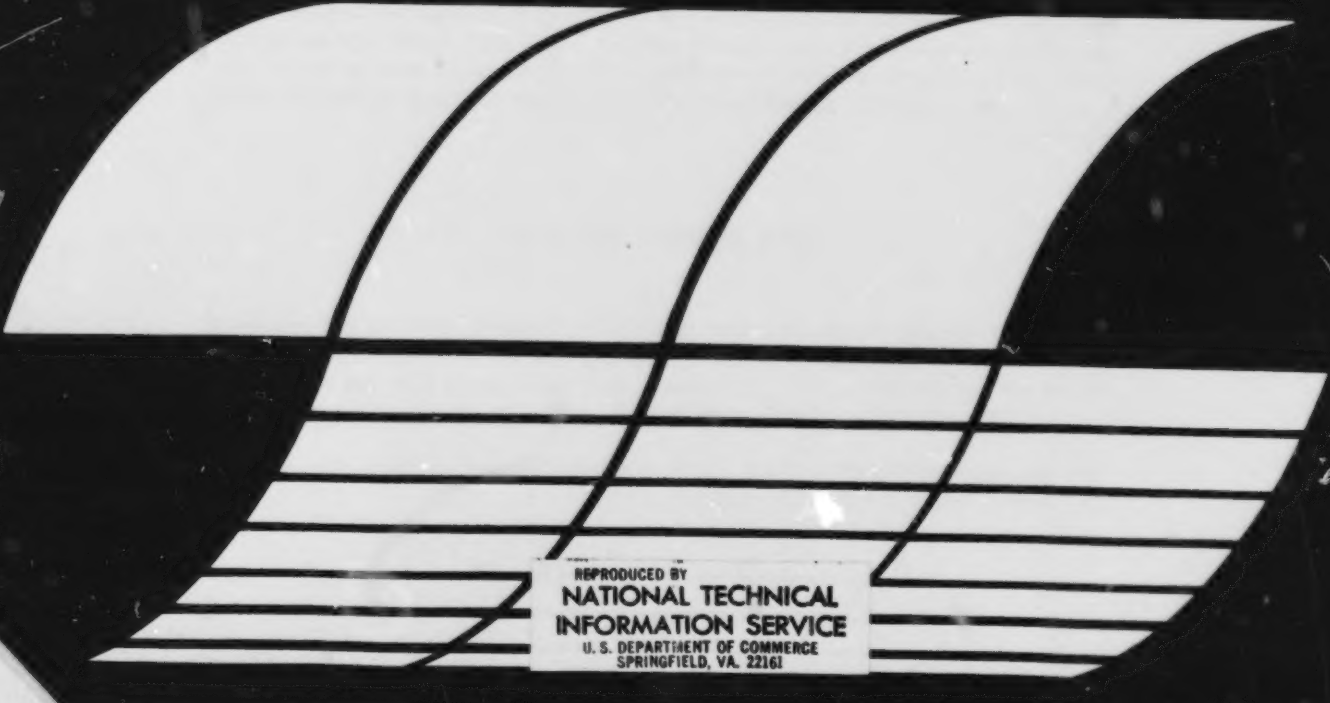

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The proceedings document the 27 presentations made during the Engineering Foundation Conference on Clean Combustion of Coal, at Rindge, NH August 1-5, 1977. Sponsored by the Environmental Protection Agency, the Energy Research and Development Administration, and the Bureau of Mines (the last two now part of the Department of Energy), the Conference dealt with the technical, economic, environmental, and policy aspects of clean combustion of coal. The five Conference sessions dealt with problem definition, precombustion processes, combustion processes, postcombustion processes, and future prospects. The Conference was intended to provide an assessment of the status and trends of clean combustion of coal.

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Conference Chairman

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INTRODUCTION

Coal is a major energy resource for the United States. The use of coal as an energy source will increase in importance over the intermediate term. While synthetic fuels from coal will be needed for specific applications, direct combustion of coal will probably continue to be the most efficient and most economical use of coal. However, the environmental problems associated with coal combustion must be solved economically and efficiently at the same time for the continued growth of utilization of this vital energy resource.

Clean combustion of coal must address issues of air quality, surface- and groundwater quality and solid waste management. Control technology for clean combustion of coal must include precombustion, combustion, and postcombustion processes. Air quality impacts from coal combustion include gaseous and particulate combustion product emissions as well as potential fugitive emissions from handling and storage. Potential pollutant emissions include NO_x, SO_x, particulates and trace elements. Generally hydrocarbon and carbon monoxide emissions are low from large coal combustors but new combustion technologies should be checked for emissions of these pollutants. Water quality impacts would result primarily from leaching of chemical compounds from the solid residues of the combustion process; this problem therefore goes hand in hand with the solid waste management problem. As a minimum, the ash in the coal must be managed. In technologies which produce additional solid waste, (precombustion, combustion, or postcombustion) an additional solid waste management problem is created.

Energy efficiency, availability, and economics must be considered in establishing acceptable methods for clean combustion of coal. One could postulate the emissions limit going to zero while paying the price of the energy efficiency going to zero as well. Therefore, it is not only a matter of technical, economic, and environmental considerations, but also policy considerations. This is recognized in the program for this conference, and while the engineering aspects of coal combustion are emphasized, the vital importance of energy policy and its impact on clean combustion of coal is highlighted.

Special thanks to the Organizing Committee for their role in establishing the program and helping to arrange for speakers.

Andrej Macek - ERDA
Albert W. Deurbrouck - Bureau of Mines
G. Blair Martin - EPA
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SESSION IA - TECHNICAL, ECONOMIC AND ENVIRONMENTAL PROBLEMS IN CLEAN COMBUSTION OF COAL

SESSION CHAIRMAN: ANDREJ MACEK, U.S. ERDA

In broad terms, we will have to learn to burn coal under very restrictive conditions. The restraints will be imposed by national policy considerations and environmental requirements. This opening session will include a general description of coal combustion technologies which are, or might become, candidates for clean combustion, and of the problems associated with these technologies. Policy considerations, which are also a key element in clean combustion of coal, will be included in the closing session of the conference. Two of the papers in this session describe four candidate technologies: fluidized bed combustion of coal, combustion of solvent-refined coal, combustion of coal/oil mixtures, and combustion of coal for direct-powered magnetohydrodynamic generators. In addition, there is a discussion of the potential environmental constraints in the forseeable future.

TECHNICAL AND ECONOMIC PROBLEMS FOR CLEAN COMBUSTION OF COAL

by

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INTRODUCTION

Ever escalating demand for limited and dwindling supplies of conventional fuel resources has been recognized as a key factor in precipitating the worldwide financial and energy crises. The gravity of these crises has forced nations around the world to look for ways and means to improve their energy supply base to meet the ever increasing demands. To meet the challenge, President Carter declared the "moral equivalent of a war" for energy independence.

Although nuclear technologies might satisfy a substantial portion of world energy needs in a distant future, there exists an immediate necessity for the development of energy technologies to conserve and efficiently use a wide base of natural resources.

Current estimates indicate the U.S. coal reserves, which are economically mineable with conventional technology, at about 600 billion tons and the overall coal resource at 3.2 trillion tons. Depending on the efficiency of mining, population growth, and growth in energy use per capita, and efficiency in end use, we have enough coal to supply our energy needs for several hundred years; sufficient, it is hoped, to carry us through a transition to a non-fossil fuel energy source. Advances in coal mining technologies and increased coal price can increase the estimate for coal which can be economically produced considerably beyond the 600 billion ton figure. Recognizing this abundance of coal, the U.S. Energy Research and Development Administration (ERDA) is greatly emphasizing the development of technologies to utilize efficiently a wide variety of coals in an environmentally acceptable manner.

The ongoing ERDA efforts in the development of fossil energy technologies are a continuation of the programs of its predecessor organizations, the U.S. Department of Interior's Office of Coal Research and Bureau of Mines. These technologies include: (1) Coal gasification, (2) Coal liquefaction, (3) Direct combustion of coal, and (4) Advanced power systems using coal and coal-based fuels.

ERDA is supporting the development of these technologies by funding various projects ranging in size from exploratory research to pilot and demonstration projects.

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ERDA's main objective is to bring up the technologies to technical maturity for commercial implementation. Although coal gasification and liquefaction are of considerable importance, this paper emphasizes the ERDA efforts in direct combustion technologies.

Direct combustion of coal in boilers and furnaces is a well established practice for heat and power generation. Only a certain fraction of the U.S. coal reserves, with low-sulfur content, termed compliance coal, can be burned directly in conventional furnaces to meet the environmental regulations if burned in conventional burners. As Dr. James Schlesinger aptly points out, "Americans want a clean environment and do not want to turn the country into something equivalent to Pittsburgh in the 1930's." Of course, all modern coal fired equipment is built for high combustion efficiency and includes a bag house or precipitator to reduce the emission of particulates, thereby avoiding the two most obvious sources of pollution from coal fired equipment, soot and fly ash. To achieve increased coal utilization while meeting stringent environmental regulations, the Government is directing the development of promising coal utilization technologies.

These technologies can be categorized as follows:

- Precombustion treatment of coal for ash and sulfur removal.
- Post combustion treatment for SO_2 removal.
- In-situ SO_2 removal at the source during coal combustion.

A brief description of these technologies follows.

Precombustion Treatment of Coal

Precombustion treatment of coal includes a number of physical and chemical approaches such as:

- Physical cleaning.
- Chemical cleaning.
- Solvent refining.

Precombustion treatment, essentially aimed at removing ash (mineral matter) and other obnoxious constituents such as sulfur in its pyritic form, increases the specific heating value (Btu/lb) and reduces the sulfur content of some coals to an environmentally acceptable level.

Physical and chemical approaches for cleaning coal are in different stages of development: A full-scale plant to demonstrate a multi-stream physical cleaning concept is being built at Homer City, Pennsylvania, and is scheduled to begin operation this year (1977). A pilot plant to test sulfur removal through chemical leaching is being built in California. Commercial implementation of this technology, depending on favorable pilot plant results, can be anticipated in the early 1980's. The impact of these technologies is to increase the availability of compliance coals by a maximum of approximately 175 million tons per year. This still leaves the majority of American coal being mined as non-compliance coal. Physical cleaning is estimated to cost about $1.50 to $4.50 per ton while chemical cleaning would cost about $10-$15 per ton.

Some variable amount of our existing coal reserves can be considered as compliance coal, based on the SO_2 emissions criteria that apply locally, and can be used in existing equipment. The Federal EPA rules on SO_2 emissions for new sources are quite definite, 1.2 lbs of SO_2 per million Btu.

Low-sulfur coal may be defined as coal that occurs naturally with a sulfur content low enough that the coal can be burned without violating applicable SO_2 emission standards. As SO_2 emission standards vary, the same coal may be considered compliance for one application but not for another. The extent to which low-sulfur coal is used to meet national ambient air quality standards (NAAQS) and New Source Performance Standards (NSPS) will depend primarily on the availability. It should also be noted that SO_3 in combustion gases, which accompanies SO_2, enhances the collection efficiency of electrostatic precipitators, so the use of low-sulfur coal at existing facilities necessitates modifications of electrostatic precipitators to control particle emissions. Low-sulfur coals with low ash fusion temperatures can cause fouling in boilers, reducing capacity and increasing maintenance costs. This has happened in several instances when western coals were used in boilers designed for eastern coals.

The availability of low-sulfur coal depends on the expeditious development of our domestic resources and of the transportation network required to get the fuel to the markets. In 1974, almost 390 million tons of coal were consumed by electric power plants; about half would comply with SO_2 emission regulations in effect on July 1, 1975. In 1980, utility coal demand is projected to be about 620 million tons with an 8% annual growth rate. In an October 1974 EPA report, low sulfur coal production in 1980 was projected to supply less than 44% of the 620 million ton demand.

The production capacity for low-sulfur coal and its use will depend on many factors, including:

(1) The relative economics of low-sulfur coal in comparison with other control approaches.

(2) The resolution of disputes over compliance schedules and state sulfur regulations.

(3) Political/economic decisions concerning low-sulfur coal recovery and distribution.

(4) The compatability of low-sulfur coal usage with existing boilers and electrostatic precipitators.

The costs of complying with SO_2 standards by using low-sulfur coal include: (1) The increased cost of the low-sulfur coal, (2) Transportation cost, and (3) The cost of power plant modifications which may be necessary. While low-sulfur coal is generally more expensive than high-sulfur coal, the price differential currently is highly variable. Transportation cost often causes significant increases in low-sulfur coal costs. Another factor to consider is that about one and one-half tons of the western coal are needed to equal the heating value of one ton of eastern coal.

Post Combustion Treatment for SO_2 Removal

Flue gas desulfurization (FGD) is a post combustion method of removing SO_2 from combustion gases. FGD processes contact the combustion gases with a sorbent to react with the SO_2.

The numerous FGD processes can be categorized as nonregenerable or regenerable processes. In nonregenerable processes, the sorbent reacts with absorbed SO_2 and is not regenerated or reused. These processes produce a sludge which consists of a mixture of fly ash and water plus calcium sulfite and calcium sulfate which result from the SO_2/sorbent reactions. Several alternatives for disposition of the sludge are available. The alternatives include ponding of untreated sludge, landfilling of untreated and treated sludge, and commercial utilization.

Regenerable processes recover SO_2 from the combustion gases and convert it into marketable by-products such as elemental sulfur or sulfuric acid.

The best developed FGD processes are the nonregenerable lime and limestone scrubbing processes. In these processes, a lime or limestone slurry absorbs SO_2 from the flue gases, and subsequent reactions produce calcium sulfite and calcium sulfate. A variation of lime/limestone scrubbing, known as the "double alkali" process, uses a clear solution of a soluble salt rather than a slurry to absorb SO_2. Subsequent reactions to produce calcium sulfite and calcium sulfate sludge occur outside the absorber.

The most significant of the regenerable processes are magnesium oxide scrubbing and sodium sulfite scrubbing (the Wellman-Lord process). The magnesium oxide process utilizes an MgO slurry to absorb SO_2 and produce magnesium sulfite and magnesium sulfate. The Wellman-Lord process employs a clear solution of sodium sulfite to absorb SO_2 and react with it to form sodium bisulfite.

The first full-scale U.S. installations of the lime and limestone scrubbing processes were operated in the late 1960's, and the processes that evolved have controversially been considered to be commercially available since 1974.

The economics of FGD are the most critical factor affecting its widespread use and also the factor that arouses the most debate. Problems of inflation, extent of redundancy, site-specific requirements, vendor optimism/user skepticism, variations in process options, variations in the kinds or quantities of by-products, differences in operating conditions, and other factors have contributed to the complexity of the situation. The cost estimates for scrubbing equipment have escalated from about \$18/kw in 1968 to about \$89/kw in 1977. On top of the equipment costs have to be added the cost of heat and power to operate the scrubbers, the additional site labor costs, interest during construction costs and escalation costs. The difference in capital costs between two new plants which are identical except that one is equipped with a scrubber is presently \$150/kw. This 400% increase is not wholly attributable to inflation. The figure does underline the difficulty of accurately projecting control costs over a period of a few years for an emerging new technology.

A member of my staff recently had the opportunity to visit a scrubber installation and closely examine the operation. The plant visited was representative of the new large coal-fired plants.

The plant consists of two 825 MW units. Steam condition is 3500 psia $1000^{o}F/1000^{o}$ and steam is supplied by a supercritical boiler to turbo-generators. The units burn pulverized coal. Operational control is by digital computer. Natural Draft cooling towers are used.

Flue gas desulfurization is accomplished by Wet Lime Scrubbers.

Capital costs for each of the two units were:

Plant and Equipment	$\$510 \times 10^6$
Scrubbers plus Cooling Tower	$\$240 \times 10^6$
	$\$750 \times 10^6$

The scrubbers are of the two vessel venturi type. The first vessel is for particulate control and the second does the sulfur absorbing. A demister follows the second vessel, then a reheater and the stack. There are six equal size parallel trains for each unit while each train handles approximately 150 MW. All six units must be worked to handle the full output. The vessels and piping are all rubber lined. The limestone is calcined separately at an installation 300 yards away, slaked, doped with MgO and piped to the units. Wet sludge is disposed of in a man-made lake with an estimated time to fill up of twenty years.

Pittsburgh seam coal, approximately 3 percent sulfur is used, most deep mined, some Ohio surface mined.

The design operation calls for a sulfur removal guarantee of 92%. 43 MW of electrical power is used to drive the scrubber and 1200 gal/hr of #2 distillate fuel oil is burned to reheat the $125^{o}F$ air from the demister to the $165^{o}F$ stack.

Nominal crew for the two units is 136 men. This does not include the extra men required to maintain and modify the scrubbers.

Commercial operation started December 1975 and the scrubbers were not yet running satisfactorily in June 1977.

Performance achieved to date has been very good considering the circumstances. The turbine-generator heat rate is 8881 Btu/kWh (which is probably due to the impluse turbines) and 9981 Btu/kWh for the whole plant. The achieved capacity factor is 71%.

The turbine, generator, and boilers work well. The scrubbers do not work well when they are operating. With six trains in parallel on each 825 MW unit, they can get some power out through the use of at least one train 91% of the time.

Sulfur removal runs ca 60% in lieu of the guarantee of 92½%.

Cost of electricity at the busbar is:

Plant		9 Mil/kWh
Scrubber		3 Mil/kWh
	Total Unit	12 Mil/kWh

The lime requirement is 7.8 percent by weight of the coal used. For a 3 percent sulfur coal, this gives a Ca/S mole ratio of approximately 1.5.

They have had endless operating troubles, and the only apparent way to minimize the problem is very, very careful control of the pH of the solution in the particulate and SO_2 absorption vessels. The pH can vary from 2 to 10 in lieu of the desired 7.

The rubber lining in the vessel and piping suffers mechanical damage from the displaced deposits. Due to the acid condition, this has eaten through the 3/8 carbon steel plate in as little as three days.

The demister chevrons and cascades plug in three days to a month. The original demister structure failed as did the succeeding two generations of replacements.

The sludge carry-over frequently plugs the lines, requiring shutdown to clear them.

Additional manpower over and above the 136 normal, runs twenty to fifty men. These are required to keep the scrubbers maintained and are a mix of power plant, vendors, and contractor personnel since the scrubbers are not accepted yet.

In summary, the new coal plant is working well except for the wet lime scrubbers. They do not work well, and add greatly to the cost at this time.

In-Situ SO_2 Removal at the Source During Coal Combustion

One ERDA approach is to develop new alternative technologies which control emissions during the combustion process or regulate input of potential pollutants. This is being pursued by fluidized-bed combustion (FBC) for heat, steam and power generation in the presence of sulfur dioxide sorbent.

The increased use of coal by this technology for heat and power will benefit the public. Coal is appropriate for use in moderate and large-sized fuel burning installations where it is economical to have equipment necessary to handle large amounts of solids (i.e., coal, limestone, ash). Increased coal use can reduce oil and natural gas use by the utility and industrial sector and make domestic supplies of these fuels available for the unique requirements of the residential, commercial and transportation sectors of the economy.

The user sectors which these programs will supply with technology are:

- Industrial and institutional heat and steam.
- Utility steam-electricity generation.

Even with a low-energy growth future, the need for new and replacement fossil-fueled equipment facilities for these user sectors represent a major market.

Emission control for fluidized-bed boilers centers in the combustion zone. Sized coal is burned at atmospheric pressure or at elevated pressures in a fluidized bed of inert ash and limestone or dolomite. The limestone or dolomite is calcined and the calcium oxide reacts with SO_2 to form a solid sulfate material which can be disposed of with the ash. Sorbent regeneration could produce a highly concentrated SO_2 gas from which elemental sulfur could be readily removed using existing processes. Fluidized-bed boilers are operated at combustion temperatures of 1500°F which are lower than conventional boilers which have flames well above 3000°F, thus inhibiting the formation of nitrogen oxides from combustion air nitrogen. This lower combustion temperature greatly reduces the tendency of slag to build-up on boiler tubes. Western coals, with high alkali content, and which foul conventional boilers rapidly, have been burned in fluidized bed research combustors without fouling. An atmospheric pressure coal-fired fluidized-bed boiler having a capacity of 5,000 pounds of steam per hour has been successfully operated for over 12,000 hours at furnace temperatures of approximately 1,600°F. It demonstrated that all types of coal, char and coal wastes can be burned in an environmentally acceptable manner.

The ERDA strategy to accomplish the development of FBC of coal is to have the majority of the technology development done in industry, to work on the technologies promising the earliest significant payoff, and to utilize experience gained on early development of small-scale equipment to benefit the development of the following larger-scale units. This reduces cost and accelerates commercial implementation. An example of the relative costs for FBC vs. conventional systems is shown in Table I for large utility applications.

The minimum risk and the best schedule of progress are achieved by performing parallel engineering development activities in several modest size and cost systems and by testing various applications at the same time. The Federal Government will expedite industrial development by providing the flexible, costly test facilities for common use that industry finds to be too expensive. By having development work performed by industrial firms with the use of these test facilities, the program can proceed rapidly to commercial implementation when the development is completed.

The user's requirements are recognized and included from the start. The industrial-institutional scale units are of of a size large enough to realize the economies of using coal, sorbent and ash handling systems, which are not economical in very small systems. Utility systems require much larger plants with very firm technical specifications, and longer construction times. Improvements which come from developments in the intermediate size industrial units will benefit the utility size systems.

TABLE I

CHARACTERISTICS OF COAL COMBUSTION

PERFORMANCE AND COST CHARACTERISTICS	Steam with AFB (3500 psi;) 1000°F/1000°F	Steam with PFB (3500 psi;) 1000°F/1000°F	Conventional Steam with FGD
Capital Cost (\$/kW)*	450 (350)**	514 (400)**	578 (450)**
O&M Cost (Mills/kWh)	2.2	2.3	2.8
Efficiency (%) (Heat Rate - Btu/kWh)	36 (9,481)	39 (8,751)	35 (9,751)
Max. Capacity Factor	.70	.70	.70
Average Capacity Factor	.60	.60	.60
Initial Capacity Factor	.50	.50	.50
Years to Reach Max. Capacity Factor (End of Year)	3	3	3
Construction Time (Years)	5	5	5
Earliest Commercialization Date	1984	1988	

* 1975 Dollars with Allowance for Funds During Construction.

** 1975 Dollars without Allowance for Funds During Construction.

The development of modular, transportable systems and components capable of factory production is to be emphasized where economically competitive with field constructed systems. This strategy will afford the program the benefits of rapid production, standardization and quality control, but of more importance from the viewpoint of national objectives, will provide an industrial production system capable of rapid expansion in the event of a political curtailment of alternative fuels.

DIRECT COMBUSTION PROGRAM

Direct combustion is the most efficient and economic method of utilizing coal.

Fluidized-bed combustion of coal has been a topic of research since the early 1960's, both in the U.S. and in Europe; in the U.S., ERDA is the manager of the Federal RD&D program for FBC. Consequently, a large data base exists to identify the technology gaps and to point out areas which require additional research. To address the relevant technical issues through the commercial implementation phase, ERDA has developed a comprehensive RD&D program for fluidized-bed combustion.

An operational pilot plant, 30-megawatt in size and designed for atmospheric pressure, represents both the largest size of fluidized-bed combustion industrial boilers and is of sufficient size to be representative of modules for electric utility boiler applications. It has superheater tubes, delivering the steam at 1325 psig and 930°F; consequently, it is more typical of a utility application. Because the unit is located in a private power company's boiler house, it will be evaluated for its capability for integrated operation in an actual operational environment.

This pilot plant is the largest fluidized-bed boiler in the world and will address scale-up problems never previously explored on a scale this large. The unit consists of four cells, three primary cells and a carbon burn-up cell. A 13 MW_e pilot plant is being designed to explore the pressurized fluidized-bed concept on a large scale.

For potential industrial applications, ERDA has developed a multi-project program to evaluate fluidized-bed combustion for both boiler and process heat applications. Several units are being built to demonstrate the technological, operational and economic viability of using fluidized-bed combustion in industrial applications. Demonstrating the viability of such systems is essential for the commercial implementation by industry.

An additional and important element in the fluidized-bed combustion program is the design and construction of component test and integration units (CTIU) for both atmospheric pressure and elevated pressure combustor operation. The CTIU's will be flexible facilities, available for use by all of industry and the research community, that will permit optimization of the combustion process/steam or heat regeneration cycle, testing of components in an integrated operating mode, and evaluation of concepts as yet untested such as the vertically stacked bed concept.

The following are descriptions of several projects being conducted by ERDA which are directly applicable to the industrial sector, where

RD&D efforts can be expected to produce near-term implementation of the technology, which will be in compliance with existing and projected emission criteria.

PROJECT: 30 MW_e AFBC BOILER

Description: Represents large-scale industrial boiler. Three parallel primary cells, each 10' x 12'. Cells operate up to 12 fps fluidizing velocity with a nominal 24" static bed in each cell (one steam generating cell, two superheat cells, plus one carbon burn-up cell). Installed in a utility generating plant. Steam conditions are 1325 psig and 930°F. Coal feed of 15 tons per hour with sorbent feed dependent on sulfur in coal.

Contractor: Pope, Evans and Robbins, Inc.

Site: Rivesville, WV, Monongahela Power Company Station

Objective: Early demonstration of FBC technology in utility environment using high-sulfur coal. Evaluate scale-up of heat transfer, combustion efficiency, emission control. Demonstrate automatic combustion control in central load dispatch utility system.

Status: Boiler installation completed. Successful ignition of coal in the carbon burn-up cell 7 December 1976. Successful start-up of superheater cell 20 April 1977.

Plans: Full load steam generation expected to begin by the end of CY 1977. A full spectrum test program will then be initiated to meet the unit/program objectives.

PROJECT: INSTITUTIONAL SIZE INDUSTRIAL FLUIDIZED-BED BOILER

Description: This fluidized-bed boiler will generate 100,000 lb per hr of saturated steam at 650 psig. The boiler will furnish this steam to a university and hospital for space heating. The boiler plant will burn high-sulfur coal while attaining low levels of pollutant emissions. The steam will be used to drive a small turbine for demonstration as a co-generation system.

Contractor: Georgetown Hospital

Site: Georgetown University, Washington, D.C.

Objective: To demonstrate an institutional saturated steam boiler capable of complete shop assembly can be built in capacities up to 150,000 lb per hr and that materials handling systems for this type of application can be optimized.

Status: Letter of intent to negotiate contract issued.

Plans: To be operational sometime in 1979. Three years operational test program and data dissemination plan under final development.

PROJECT: INDUSTRIAL APPLICATION FLUIDIZED-BED COMBUSTION PROCESS - TWO UNITS

Description: The work plan is divided into two phases, subscale testing of natural circulation design capability and design and testing of a demonstration natural circulation fluidized bed boiler. This demonstration unit will generate 50,000 lbs of steam per hour at 500 psig and 600°F, or about 120°F of superheat.

Contractor: Combustion Engineering, Inc.

Site: Great Lakes Naval Training Center

Objective: Confirm the subscale test data design parameters and procedures subsequently developed. Provide endurance test data on materials. Provide design information for possible improvements to demonstration and subsequent units.

Status: Letter of intent to negotiate contract issued.

Plans: Subscale design through testing for the natural circulation unit will take 1-3/4 years from contract initiation. Demonstration design through testing will take two years.

PROJECT: INDUSTRIAL BOILER

Description: Develop a demonstration multi-solids fluidized-bed boiler. Basically, a multi-solids FBC can be regarded as a recirculating or entrained fluidized-bed superimposed on a conventional dense fluidized bed region using fluidizing velocities as high as 35-40 fps. Heat transfer advantages are expected. The demonstration unit for this process is to generate 25,000 lb/hr of saturated steam at 100 psig.

Contractor: Battelle Memorial Institute's Columbus Laboratories

Site: Columbus, Ohio

Objective: Development of the multi-solids FBC system to the point where industry will accept and use it for commercial industrial steam generation.

Status: Contract signed.

Plans: Phase I - R&D in support of demonstration plant (25 months duration); Phase II - Construction and start-up of demonstration plant (14 months duration); Phase III - Demonstration plant operation (36 months duration).

PROJECT: FBC PROCESS HEATER/TUBE STILL

Description: Evaluate the FBC concept for fluid process heaters such as those used in refineries. A Process Development Unit (PDU) will be designed and constructed to test a fired heater in the 10-15MM Btu per hour range for application to a tube still.

Contractor: EXXON Research and Engineering Company

Site: Linden, New Jersey (Engineering)
PDU Location at Refinery

Objective: Conduct R&D to obtain engineering design data for coal fired fluid bed process heaters. Demonstrate operation of the PDU. Prepare design specifications and cost estimate for a commercial FBC process heater.

Status: Contract signed.

Plans: Phase I - R&D test work (18 months duration); Phase II - PDU design (6 months duration); Phase III - PDU evaluation and commercial design (12 months duration starting two years after contract initiation).

PROJECT: FBC PROCESS HEATER/AIR HEATER

Description: The FBC heater will supply 39 x 10^6 Btu per hour to heat clean air to 900°F in the heat exchanger. The total load will be served by three beds with a thermal storage unit in the system to provide heat during intermittent operation of each bed to achieve load matching. Bituminous coal, lignite, refinery coke, peat as primary fuels and such things as wood and paper waste plus cornstalks as secondary fuels will be burned.

Contractor: Fluidyne Engineering Corporation

Site: Owatonna, Minnesota

Objective: Demonstrate FBC heating of clean, low-pressure air to 900°F. Provide long-term data on life of air tubes in and above the bed at different temperatures. Prove application to manufacturing processes and space heating.

Status: Contract signed.

Plans: Construct by late 1978 or early 1979.

Another facet of the ERDA direct combustion program that is accelerating in importance is the use of western coals in FBC units. The future of the western coals as compliance coals could heavily depend on FBC.

The ash of lignites and western subbituminous coals contains a high percentage of the alkali constituents, calcium, magnesium, and sodium. These coals, when burned in a conventional pc-fired furnace, will retain from 10 to 40 percent of the sulfur on the ash. These same coals, when burned in a fluidized-bed combustor, should retain a greater percentage of sulfur on the ash because of: (1) The increased contact time between the sulfur dioxide produced during the combustion process and the inherent ash alkali, and (2) The lower combustion temperatures for the fluidized combustion process. The longer contact time allows for the reaction between coal ash alkali, oxygen, and SO_2 to be carried further towards completion. The lower temperatures allow for greater alkali utilization because the temperatures are below the disassociation temperature of the sulfates and below the ash fusion temperatures so that the alkali is not tied up in the glassy agglomerate. The sulfur retention percentages obtained in preliminary tests on one North Dakota lignite at the Grand Forks Energy Research Center range from 38 to 58 percent without ash reinjection.

The role of the Grand Forks Energy Research Center of ERDA in the fluidized-bed combustion program is to develop data on sulfur retention on the alkaline coal ash from western United States coals, when burned in a fluidized-bed combustor without a sorbent. FBC will result in substantially lower SO_2 emissions than from conventional combustion systems, and may therefore meet the Federal New Source Performance Standard of 1.2 lb $SO_2/10^6$ Btu or even new lower federal or local emission level. The effects of operating conditions and coal ash composition on the retention of sulfur dioxide during fluidized-bed combustion of western coals is being thoroughly evaluated to provide a design base for the use of these coals.

Six coals from the western United States other than the lignite previously mentioned have been tested in the fluidized-bed combustor at Grand Forks. Preliminary results are presented in Table II. Recycle was not used for these tests. The sulfur retention would be expected to improve significantly with recycle.

It must be emphasized that this work with western coals was done without a sorbent addition or a sorbent bed. The importance here is certainly both in improving the economics of FBC and in making the auxiliaries less complicated. The bottom line, however, is in the significant impact of making currently non-compliance western coals compliance coals in FBC without the use of a sorbent. As a bonus, the low temperatures used with FBC will minimize or eliminate the fouling/slagging experienced in conventional units with these fuels.

Coal Conversion Processes

The mandatory increase in the use of coal over the next quarter to half of a century mandates the widespread application of control technologies, especially for SO_2, singly and in combination, to prevent extensive degradation of the environment. An SO_2 control program which permits timely and economic attainment of the regulatory requirements is essential. Such a program will be comprised of various control options including naturally occurring low-sulfur coal, coal cleaning and flue gas desulfurization separately or in combination, coal gasification, coal liquefaction, fluidized-bed combustion of coal, and others. Coal gasification and liquefaction are viewed as SO_2 control technologies for the overall program.

The choice of appropriate SO_2 control strategy for a specific site is often complex due to the interaction of such factors as commercial availability of competing systems, reliability and operability of the systems in other applications, capital costs and annual revenue requirements, fluctuation in the availability and cost of low-sulfur fuels, and uncertainty about pollutant emission regulations.

TABLE II

PRELIMINARY SULFUR DIOXIDE AND NITRIC OXIDE EMISSION DATA FOR VARIOUS WESTERN COALS AND LIGNITES

Rank	Coal Tested	Calcium-to-Sulfur Mole Ratio	Total Alkali-to-Sulfur Mole Ratio	Percent			Emission, ppm @ 45% excess air	
				Coal Sulfur	Ash	Coal Nitrogen	Sulfur Dioxide	NO_x
L[1]	Beulah, N. Dak.	1.27	1.99	1.01	7.49	0.45	480	340
S.B.[2]	Naughton, Wyo.	0.67	1.09	0.34	5.04	1.15[4]	307	400
L	Velva, N. Dak.	5.09	7.54	0.23	6.36	0.76[4]	10	390
S.B.	Colstrip, Mont.	1.29	1.87	0.62	8.16	0.69[4]	.377	360
B[3]	Browning, Utah	0.81	1.23	0.88	8.07	1.28[4]	588	400
S.B.	Sarpy Creek, Mont.	1.56	2.18	0.71	8.98	0.68[4]	412	339
S.B.	Decker, Mont.	1.38	2.48	0.33	4.25	1.02[4]	121	350

[1] Lignite.

[2] Subbituminous.

[3] Bituminous.

[4] Percent of nitrogen not available for specific sample burned in FBC. Data taken from earlier sample of same coal.

Depending on application and end product, specific gasification processes can be described by one or more of the following terms: low-Btu, intermediate Btu, high Btu, fixed bed, entrained bed, fluidized bed, slagging, air blown, oxygen blown, atmospheric and pressurized.

Gasifier systems like Lurgi, Winkler, Wellman-Galusha, Koppers-Totzek, HyGas, Bi-Gas, Synthane, CO_2-Acceptor, Texaco, Riley-Morgan, U-Gas, and COGAS are familiar names to those who have followed the history of coal gasification. Sulfur clean-up systems such as Stretford, iron oxide, Benfield, fluidized bed dolomite, Trencor, Selexol, Sulfinol, and Rectisol are partner systems well known to the industry.

Considerable research, development, and engineering have already taken place in coal gasification and some systems are commercially available and are used around the world. Installations of the small sized Lurgi, Winkler, Koppers-Totzek, and Wellman-Galusha gasifiers are too numerous for mention here and these are definitely considered commercial. New combinations of or scale-ups of these gasifiers, along with H_2S and particulate matter removal systems need to be coupled in practice.

Economics of the leading coal gasification systems are available from a number of studies completed during recent years. TVA has conducted considerable work in evaluating the economics of coal gasification and H_2S removal systems. Economic analyses of 500 MW power units with sulfur production of about 218 tons per day, indicated the following direct capital cost (in 1975 dollars) and annual revenue requirements for 7,000 hours/year of operation:

	Direct Capital Investment		
Process	Without Claus	With Claus	Annual Revenue Requirements
Stretford	$18,000,000	Not needed	$3,400,000
Benfield	5,000,000	$10,000,000	3,600,000
Trencor		10,000,000	3,800,000
Selexol	12,000,000	17,000,000	3,500,000

Total project cost would be somewhat higher than the direct costs indicated.

Economics for new combined cycle plants depend a great deal on the state-of-the-art of gas turbine operation. For existing gas turbine technology where the maximum temperature is around 1950°F, power generation via a coal gasification unit integrated into a combined cycle plant is more expensive than power generation with conventional boilers with FGD supplying steam to a conventional steam turbine plant. If the advancement of the gas turbine technology permits turbine temperatures up to 2500°F, the advantage could possibly switch to the gasification-combined cycle units.

Liquid fuels can be produced from coal by four general methods. First, the coal can be pyrolyzed to break it down into a synthetic crude oil, a by-product gas, and a char residue. The char residue must be used in some way since it represents a significant fraction of the total heating value of the coal. Second, the coal can be dissolved in an organic solvent, treated with hydrogen, and filtered to remove the noncombustible minerals. The combustible fraction filtered out with the non-combustibles must be reclaimed and used if the process is to be economically competitive with alternative technologies. Third, the coal can be gasified to produce carbon monoxide and hydrogen which can subsequently be converted to methanol or other liquid hydrocarbon fuels. Fourth, pulverized coal can be contacted with hydrogen in the presence of catalysts to form fractions of liquid and gaseous hydrocarbons.

The economic aspects of coal liquefaction are not well defined since the technology is still being developed. Some studies were made earlier in the development of the technology, but these estimates were optimistic and are generally not regarded as accurate. The preparation of additional estimates is now underway on many of the systems. In general, the cost of coal liquefaction is comparatively high; base load power generation using fuels from these processes is probably not economically competitive with low-Btu coal gasification, fluidized-bed combustion, or conventional boilers with FGD. Coal liquefaction will undoubtedly find application for intermediate duty & peaking service, where it is much more competitive with other technologies.

Conclusion

The accelerated use of coal in our national energy picture brings along with it some interesting points. It is going to be expensive. It is a definite technology challenge; a surmountable one, but definitely complex. The environment can be protected. Currently, the direct combustion of coal in a fluidized-bed would appear to have the overall edge when the technical and economic impacts are evaluated against some baseline environmental compliance criteria; however, it would appear that we will have a continuing need for both liquid and gaseous conversion fuels to meet our diverse utility/industrial energy consumer fuel needs.

COAL COMBUSTION AND FUTURE EMISSION REGULATIONS

by

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It is a pleasure for me to be here this morning and have the opportunity to talk with a group of professionals who are involved with many of the same problems that are important to my work at the Environmental Protection Agency.

As Dr. Freedman highlighted earlier this morning, the concern for clean air has had and will have a considerable impact on the pattern and techniques of burning coal. My intent this morning is to talk primarily about environmental policy and future emission regulations for coal burning sources. I will discuss three major areas which have considerable effect on the implementation of clean coal technologies. These are:

- emissions standards which are to be met by new facilities,
- regulations to prevent the significant deterioration of air quality, and
- limitations necessary to attain air quality standards and protect public health.

As you appreciate, each of these areas will have an effect on the demand, or market, for clean coal combustion technologies. Moreover, as you might expect the technical capability of clean technologies will greatly influence the emission regulations in each of these cases.

Over the next 15 years coal will become an increasing energy resource. The shift to coal is already occurring due to the existing scarcity and price of oil and natural gas. The President's proposed National Energy Plan is to encourage the substitution of coal for gas and oil through taxes on oil and gas and through investment tax credits for the purchase of coal handling and burning equipment, including pollution control.

With increased coal use comes increases in atmosphere emissions of a number of pollutants--sulfur oxides, particulate matter, nitrogen oxides, trace metals, radioactive materials, and organic compounds. The potential damages are very real; they include:

- Impaired health and premature death from respiratory ailments;
- Stunted growth of crops and other plants;
- Reduced resistance of plants and animals to disease.

Air quality standards and pollution emission regulations are intended to protect against these damages.

New Source Performance Standards

The application of clean combustion technologies at new facilities will be important to minimize these effects. In this regard, the Environmental Protection Agency prescribes nationally applicable standards of performance for large new sources of air pollution. The 1970 amendments to the Clean Air Act specified that the new source performance standard, NSPS for short, was to reflect the degree of emission limitation achievable through the application of the best, adequately demonstrated system of emission reduction taking the costs of achieving the reduction into account.

Under this authority, EPA promulgated new source performance standards for large coal-fired boilers in 1971. Considering the regulation for sulfur dioxide presently in effect, the specific regulation of 1.2 pounds of sulfur dioxide per million Btu of heat input can be met by burning low sulfur coals or by burning high sulfur coal with pollution control equipment. Although such a regulation may have been appropriate for the early 1970's when commercial use of pollution control equipment and clean combustion technologies was just emerging, Congress has stated that it considers a standard which permits the use of untreated fuels to be inadequate and in direct conflict with the purposes of new source standards. Accordingly, in the Clean Air Act Amendments considered in 1976 and proposed again this year, the House of Representatives and the Conference Committee have adopted legislative language which would require that the new source standard for new fuel-burning stationary sources require a specified reduction in emissions which is achievable when applying the best control technology. In establishing the standard, EPA would be required to determine which technologies were adequately demonstrated and to consider cost impacts and the energy and non-air quality impacts before setting a regulation.

Anticipating the passage of the amendments this year and considering recent advances in control technology development, EPA has already initiated a review of the new source standards for electric power plants. In what is one of the most rigorous analyses performed by the Agency, EPA is evaluating the technical performance (primarily reliability and removal efficiency) of recent flue gas desulfurization systems. In addition, the Agency is assessing potential coal production shifts and estimating the economic impact on the electric utility industry and its customers. While several alternative emission regulations are being considered, one guess at the new standards would be a requirement for 90 percent removal of sulfur dioxide with an emission ceiling somewhere between 0.5 and 1.2 pounds of sulfur dioxide per million Btu, a regulation of 0.05 pounds per million Btu (one-half the present standards) for suspended particulates, and an incremental tightening to 0.6 pounds per million Btu for NO_x. The new standards for power plants are expected to be proposed in early 1978.

The implications of these standards, especially for sulfur dioxide, for developing clean combustion technologies are significant. They set both a performance and a cost target with which other technologies must compete. For example, to be allowed as a substitute for a flue gas desulfurization (FGD) system, a sulfur removal technology would have to achieve comparable or better sulfur removal efficiency. Use of coal washing alone would not be suitable unless it were combined with another technique to achieve the required overall reduction in emissions. In effect, this could mean that those technologies which are not capable of high removal and are not economically competitive when used in combination with other technologies would be foreclosed from use on new coal-fired power plants.

While requiring the maximum available degree of emission reduction from new sources, it is hoped that development of innovative means of achieving equal or better degrees of emission control would also be encouraged. In this regard, it has been EPA policy to allow special consideration for developing technologies. To encourage innovative technology, Congress has also proposed a formal variance for new technologies for up to 10 years from the federal new source performance standards. Only those technologies with promise of achieving equivalent or greater emission control than that required under the NSPS would be eligible for a variance.

Continued progress in control technology development for each pollutant is expected to lead to competition in both performance and costs. At some date in the future, with the demonstration of greater emission removal efficiency at a reasonable cost, EPA would again revise the new source performance standards to reflect new technical capabilities.

Prevention of Significant Deterioration

At this point I would like to discuss the regulations to prevent the significant deterioration (PSD) of air quality in areas of the country which are presently enjoying clean air. As you all probably know, the Supreme Court upheld a lower court decision that required EPA to promulgate regulations to prevent the significant deterioration of air quality. These regulations were promulgated in December 1974 after extensive technical analyses and public participation and provide air quality designations which States may use to manage air resources.

Briefly, the EPA regulations establish three classifications of air quality levels based on how much increase will be permitted in ambient concentrations of particulate matter and sulfur dioxide.

Class I - Pristine areas where deterioration in any air quality deterioration would be considered significant.

Class II - Areas where deterioration in air quality that would normally accompany moderate growth would not be considered significant.

Class III - Areas where intensive and concentrated major industrial growth is desired, thus permitting levels of air quality to rise to the national ambient air quality standards.

EPA's regulations initially designated all areas of the country as Class II, allowing states to redesignate areas to either Class I (pristine) or Class III (intensive economic growth). The regulations passed by the Senate and House are similar in general approach, although numeric limits, Class I designations, and sources covered vary.

Briefly, the regulations are intimately tied to the capability to control emissions of pollutants. Limits on size of facility or possible constraints on siting a large facility within the requirements of each air quality designation depends upon the ambient ground-level concentrations produced by the facility. Since ground-level concentrations are roughly proportional to emission rates, any constraints on a facility translate into a need for greater emission control.

For example, consider a national park or wilderness area which is protected as a Class I, or pristine, area. In order to preserve the clean air values of this area, a 1000 Mw coal-fired power plant meeting the present NSPS for sulfur dioxide would have to locate approximately 60 miles from the Class I boundary. Depending upon the emission rate and the specific terrain in the Class I area, a 1000 Mw plant could locate less than 10 miles from the park or wilderness area. A significant portion of this distance reduction would be accomplished by the planned revision in the NSPS for sulfur dioxide. And, in reality, the demand for additional emission control due to PSD requirements may be small. It will, however, be one option considered by large power plants, synthetic fuel plants, and other facilities which wish to locate near Class I areas or near mountainous terrain.

Attainment of Air Quality Standards

The last topic I would like to address concerns the measures necessary to protect public health in areas which presently have poor air quality.

The 1970 Clean Air Act required each State to develop and implement a State Implementation Plan (SIP) to attain national, health-related air quality standards. The Act provided for attainment of the air quality standards by mid-1975. 1975 has come and gone and there remain a number of areas, primarily metropolitan areas, which are not attaining these health standards. Further, there are other areas which may have difficulty maintaining air quality standards as industry and population grow.

These problems are cause for considerable concern from the standpoint of public health. If we are to progress toward attaining our health standards we are faced with either requiring greater emission control on existing sources or limiting the construction of new sources in these problem areas.

Although the nonattainment problem is most widespread with respect to photochemical oxidants and particulates, NO_x and sulfur dioxide are also problems in specific cases. To manage new growth in these areas, EPA adopted an interpretative ruling in December 1976. Referred to as an "emission offset policy," the ruling allows new sources to locate in areas not attaining health standards if the new facility meets the lowest achievable emission rate (comparable to best controls on fuels of moderate or low pollution potential) and a decrease in emissions from existing sources more than offsetting the emission increase from the new facility. The emission decreases can be from other resources operated by the owner of the new facility or from existing facilities operated by others.

The EPA policy is one approach which will lead to attainment of air quality standards. In effect, the policy creates an incentive for States and local communities to adopt and enforce emission regulations which will attain the air quality standards.

EPA has issued calls to a number of States to revise their SIPs to assure attainment of air quality standards as soon as possible. In addition, the Agency has designated at a number of other areas as air quality maintenance areas. These areas may require some adjustment in emission regulations to assure maintenance of air quality due to anticipated growth in population and industrial activity between now and 1985.

In formulating SIP emission limits or in meeting the requirements of the emission offset policy a central question is the technical feasibility and cost of different levels of control on different types of sources. Thus, here, as with NSPS, the technical feasibility and affordability of clean combustion technologies will determine the nature of emission limits. The best technologies for new sources would be relied upon to achieve the lowest possible emissions and thereby minimize the air quality effects of new facilities. Moreover, the available technologies will establish the bounds for the emission regulations which could apply to existing and smaller facilities. In this latter case, the precombustion treatment of fuels and those technologies that are economic to retrofit will be particularly important.

Conclusion

In closing, I would like to read a paragraph from the National Academy of Science publication on Man, Materials, and Environment, (pp. 8-9):

> Many foreseeable problems cannot now be solved by available technology. Even if we control 99.5 percent of some pollutants, the remaining one-half of 1 percent, because of the large absolute amounts projected by the year 2000, can create environmental problems for which a workable remedy has not yet emerged from the laboratory.

RECENT DEVELOPMENTS IN COAL COMBUSTION TECHNOLOGY

by

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ABSTRACT

This paper considers three distinct areas of research and development directed toward increasing the utilization of coal by industry and electrical utilities: coal-oil slurry combustion; solvent-refined-coal combustion; and coal-based magnetohydrodynamic power generation. Current research programs at the Pittsburgh Energy Research Center are discussed, and an assessment of technical problems that require solution is presented. Finally, an attempt is made to predict the potential impact of each of these technologies on the U. S. energy supply situation.

I. INTRODUCTION

The increasing dependence of the U. S. on foreign supplies of petroleum and the growing scarcity of domestic natural gas have placed increased emphasis on developing technology to utilize our vast coal resources in an environmentally acceptable manner. Three approaches to accomplishing this objective are discussed in this paper.

The first approach considered involves retrofitting existing utility and industrial boilers to burn coal-oil slurry. The use of coal mixed with heavy fuel oil could conserve 25 to 35 percent of the oil now used for steam raising, and could be implemented almost immediately.

The advent of low-sulfur, low-ash fuels derived from coal, such as solvent refined coal (SRC), could make an impact on our energy supply situtation in the mid-term (1985-2000). Use of such fuels would be preferable to the use of fuel oil or natural gas for power generation, and may provide an attractive alternative to flue gas scrubbing.

The development of coal-based magnetohydrodynamic (MHD) power generation holds great promise for the period 1990 and beyond. This approach to utilizing coal offers a highly efficient means for generating electricity with minimal degradation of the environment.

The combustion-related aspects of each of these approaches to coal utilization will be considered. Current research programs in coal-oil slurry combustion, SRC combustion, and MHD combustor development at the Pittsburgh Energy Research Center (PERC) are reviewed, and the status of each of these technologies is assessed.

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II. COAL-OIL SLURRY

The concept of burning coal and oil together as a slurry is not novel. Numerous reports dealing with the handling and combustion characteristics of slurries have been published, the earliest appearing nearly 100 years ago. Research on coal-oil slurries was particularly active during the period between World War I and World War II*.

The main incentive for utilizing coal-oil slurries in lieu of fuel oil alone is simply that a significant reduction in oil usage can be achieved by substituting coal for oil. Systems designed for feeding and burning liquid fuels can still be employed, with some modifications.

For a slurry containing 40 weight percent coal, a fuel oil savings of 26 to 34 percent is possible for coals ranging in heating value from 10,000 to 14,000 Btu/lb. Based on earlier studies by the U. S. Bureau of Mines and Kansas State College, the maximum allowable concentration of coal appears to fall in the range of 40 to 50 percent[2,3].

For a 1 percent sulfur coal, a slurry containing about 50 percent coal could be used without violating EPA emission standards for SO_2, assuming a 13,000 Btu/lb coal. With a 2 percent sulfur coal, however, stack gas scrubbing would be necessary if the slurry coal-content exceeded about 17 percent.

A number of potential problems may arise in attempting to convert an existing oil-fired facility to coal-oil slurry firing. These include: 1) erosion and/or corrosion of piping, valves, flow meters, pumps, and burners; 2) erosion or fouling of boiler tubes; 3) deposition of solids in various system components; and 4) particulate and gaseous emissions. An additional concern results from the tendency of the coal to settle out of the slurry when stored; efforts to develop an effective and inexpensive "stabilizer" have been only partially successful[2,3]. While a fair amount of success was achieved in early short-duration combustion tests with slurries (see Reference 1), not all of the problem areas listed above have been addressed.

A coal-oil slurry combustion research program was initiated at PERC in June 1975[1]. The initial objectives of the program were to delineate problems associated with firing coal-oil slurry in a package boiler designed to burn oil or gas, and to determine the effect of coal ash on the boiler components and feed system over an extended period (1000 hours). The boiler used was a 100 HP Cleaver-Brooks firetube type with four passes. The fuel used throughout the test period consisted of a 20 percent by weight concentration of Pittsburgh seam coal in No. 6 fuel oil. The coal size consist was nominally 90 percent minus 200 mesh.

The major difficulty that persisted throughout the test period was formation of carbonaceous deposits in the refractory-lined burner zone in the combustion chamber, resulting from impingement of the flame on the refractory. It was necessary to shut the boiler down frequently to remove the deposits.

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*An extensive bibliography of literature relating to coal-oil slurries is given in Reference 1.

Increasing atomizing air pressure and excess air level was only partially successful in limiting the rate of deposition. Reduction of load to about 80 percent of capacity also increased operating time. Further improvement was achieved by modifying the nozzle to provide a narrower flame pattern which reduced impingement. However, deterioration of the spray pattern occurred due to erosion of the orifices in the original brass nozzle, and in some instances the nozzle had to be replaced after 100 hours of operating time.

After completion of the 1000 hour test, the boiler was opened and the internal tube surfaces were inspected. Only a light coating was evident, and there was no indication of slag deposition on any of the surfaces. The test tubes installed in the second, third, and fourth passes were removed from the boiler and sent to an independent testing laboratory for metallographic examinination. The analysis indicated that there was no evidence of intergranular or subscale corrosion attack. Estimated corrosion rates were 0.94, 0.68, and 1.2 mils per year in the second, third, and fourth passes, respectively; these are considered to be acceptable rates.

Subsequent to the 1000-hour test, the 100 HP test facility was upgraded with respect to instrumentation and controls. Problems due to formation of carbonaceous deposits in the burner zone have now been completely overcome as a result of modifications to the burner diffuser. The unit was recently operated for 65 continuous hours burning a slurry containing 30 percent coal. The test was considered satisfactory in all respects, and an efficiency of 79.9 percent was achieved at full boiler load.

A comprehensive research program has now been initiated at PERC directed toward evaluation of the flame characteristics of coal-oil slurries. Combustion aerodynamics and heat transfer in the combustion zone of the 100 HP unit (first pass) will be examined in detail and existing mathematical models will be modified and applied to the system to aid in interpretation of data. Coal concentration, coal size-consist, and boiler load will be varied systematically and an attempt will be made to develop fundamental design criteria for slurry-fired systems. In addition, laboratory studies of slurry rheological properties will be conducted, and various slurry stabilizers will be tested.

Much of the experience gained to date with the 100 HP boiler has aided in the design of a larger coal-oil slurry test facility now under construction at PERC. This facility will include a 700 HP watertube boiler which is more representative of the type of boiler employed in industry. The 700 HP combustion test facility will be highly instrumented and equipped with a data acquisition system. Shakedown tests are expected to begin in March 1978.

In addition to the program at PERC, ERDA is sponsoring several industrial organizations in large-scale testing of coal-oil slurry[4]. Studies have also been conducted by a consortium of companies headed by General Motors, with support from ERDA[5].

III. SOLVENT REFINED COAL

Solvent Refined Coal (SRC) is a low-sulfur, low-ash solid with a solidification point of 300°F to 400°F[6-9]. The technology for producing SRC has been successfully piloted at a 6 ton/day plant in Wilsonville, Alabama, and at a 50 ton/day plant in Fort Lewis (Tacoma) Washington.

The properties of SRC are remarkably unaffected by the quality of the original feedstock. Typically, the final product contains 0.5 to 0.8 percent sulfur, less than 0.25 percent ash, and has a heating value of 15,500 to 16,000 Btu/lb. A fuel with these specifications would meet federal standards for SO_2 emissions from new stationary sources (1.2 lb $SO_2/10^6$ Btu for a coal-fired station). Utilization of SRC in industrial or utility boilers would eliminate, or at least minimize, the need for elaborate flue-gas cleanup systems.

Early studies (1964-1965) of the handling and combustion characteristics of SRC by Babcock and Wilcox, Combustion Engineering, and the U. S. Bureau of Mines were inconclusive[10-12]. At that time, only limited quantities of SRC were available and the testing programs were too brief to resolve difficulties encountered. However, all investigators reported problems with respect to pulverizing and conveying the fuel, and burner fouling, when attempting to burn SRC as a solid. To fire SRC as a liquid, it was necessary to heat the fuel to 700-800°F, which resulted in evolution of vapors at about 350°F and severe foaming at about 650°F.

Research on the combustion and handling of characteristics of SRC were initiated at PERC in 1974. Analysis of the earlier studies of SRC combustion indicated that firing of the fuel as a solid would present fewer difficulties than firing as a liquid. With solid SRC, no external heating of pumps, transport lines, or fittings is required, and problems with respect to devolatilization or foaming of the liquid are avoided.

The SRC used in this investigation was obtained from the Southern Services, Inc. pilot plant in Wilsonville, Alabama and from the Fort Lewis, Washington, pilot plant operated by Pittsburg and Midway Coal Co. for ERDA.

In contrast to earlier investigations of SRC properties, no problems were encountered in pulverizing or transporting the fuels used in this study. An impact mill was used rather than a hammer mill or ball-and-race mill; attempts to use the latter two types had resulted in mill plugging due to softening and agglomeration of the SRC. The grind obtained was about 90% through 200 mesh, somewhat finer than that usually obtained when pulverizing coal in the same mill.

Initial attempts to burn SRC with the burner usually used in coal combustion studies resulted in clogging of burner passages due to SRC melting upon contact with hot burner surfaces. Water cooling was provided to all surfaces which contacted the fuel prior to entry into the furnace; a water-cooled deflector was added to protect the oncoming fuel stream from flame radiation; and port velocity was increased to 100 ft/sec. These modifications permitted trouble-free operation.

Most of the SRC combustion tests* were conducted at fuel rates of 425 lb/hr (≈6.5 million Btu/hr) at stoichiometric air levels ranging from 115 to 140%, and with air preheat temperatures of 540°F. In almost all tests, carbon combustion efficiencies in excess of 99% were achieved (conversion was 98.5% at 115% S.A.). NO_x emissions ranged from about 0.45 to 0.72 lb $NO_2/10^6$ Btu, increasing with increasing stoichiometric air levels. Compliance with EPA emission standards of 0.7 lb $NO_2/10^6$ Btu could easily be achieved by operation at less than 130 percent of stoichiometric air.

Recent studies of SRC combustion have also been carried out by Babcock and Wilcox[15], and Combustion Engineering[16]. B&W reported that SRC could be pulverized easily with an impact mill but that extreme difficulties were encountered with a ball-and-race mill; combustion tests were successfully conducted using a water-cooled burner. Combustion Engineering carried out a 100 hour combustion test with SRC with no major problems. It was concluded that SRC could be pulverized readily using a C-E bowl mill, and that it could be fired using conventional fuel admission assemblies provided with water cooling.

A large-scale combustion test** using SRC has recently been completed at Plant Mitchell owned by the Georgia Power Co. The 22.5 MW B&W boiler used was equipped with modified B&W dual-register burners. The test was considered a success in all respects with no problems encountered in pulverizing, transporting, or burning of the SRC. SO_2 and NO_x emissions were substantially less than EPA standards for solid fuel firing.

IV. COAL COMBUSTORS FOR MHD POWER GENERATION

A promising technique for improving the efficiency in converting thermal energy into electricity involves the principles of magnetohydrodynamics (MHD). In an MHD power plant, electricity is generated by passing a high-temperature, electrically conducting fluid (or plasma) through a magnetic field. The interaction of the conducting fluid with the magnetic field results in a flow of electrons which can be collected by electrodes on the walls of the MHD generator.

To enhance the electrical conductivity of the plasma, a "seed" material, such as potassium carbonate, is injected into the high-temperature gases produced in the combustion system. In coal-fired systems, it has been shown experimentally that the potassium reacts with SO_2 to produce K_2SO_4 which can be collected as a solid in downstream components. The K_2SO_4 can be regenerated to K_2CO_3, thereby recovering the seed and producing elemental sulfur. The economic requirement for recycling seed also results in a built-in pollution control technique. Nearly quantitative removal of sulfur oxides can be achieved.

The combustion products leaving the MHD generator are at a sufficiently high temperature to generate additional power in a "bottoming" steam-turbine plant. The recently completed Energy Conversion Alternatives Study (ECAS)[17] concluded that a combined open-cycle MHD-steam power plant offers overall efficiencies greater than 50 percent as compared to the predicted performance of advanced "conventional" steam plants of about 40 percent.

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* Detailed experimental results are reported in References 13 and 14.

** Sponsored by ERDA in cooperation with Southern Company Services, EPRI, Pittsburg and Midway Coal Company, and Babcock and Wilcox.

There is now an active ERDA-sponsored national MHD development program[8,18]. The goal of the program is to place in operation a commercial scale demonstration plant, fueled by coal, by the 1990's.

The discussion here will be confined to MHD coal combustion systems. The reader is referred to recent publications[8,18,19] for a description of the overall national MHD program and development activities involving other MHD system components.

The development of high-temperature combustion systems for MHD applications was begun in the early 1960's[20]. Most of the progress to date has resulted from programs in Great Britain, the USSR, and the USA. The work in Great Britain, discontinued in 1968, was geared to the use of coal and, to a lesser extent, oil. Efforts in the USSR have been directed primarily toward development of natural gas combustors, although some research in coal combustion has also been conducted. In the United States, current research is oriented toward development of coal-fired systems exclusively.

A. Combustor Design Considerations

Combustors for open-cycle MHD power plants are actually plasma generators. Although similar to conventional combustion systems in some respects, there are certain aspects of MHD combustors that are unique. An MHD combustor must be able to meet the following design requirements:

1. Burn natural gas, oil, or coal with high efficiency (approaching 100 percent).
2. Produce a working fluid with a temperature of 2700-3100 K (4400-5100°F).
3. Operate at pressures ranging from 5 to 10 atmospheres.
4. Accommodate highly preheated oxidizer at a temperature of 1800-2000 K (2780-3140°F), and possibly up to 2300 K (3680°F) in future plants .
5. Exhibit low heat losses (preferably 5 percent or less of the fuel thermal input).
6. Incur low pressure losses (preferably less than 10 percent of the oxidizer inlet pressure).
7. Accommodate injection of seed in dry or aqueous form (preferably dry).
8. Provide a high degree of seed ionization (approaching 100 percent).
9. Produce a uniform plasma.

10. Operate with low levels of instabilities.

11. Have a long operating life (many thousands of hours).

12. Operate under conditions conducive to control of nitrogen oxides; the formation of nitrogen oxides must be suppressed sufficiently to allow their decomposition as the gases pass through the MHD plant.

In addition to meeting these general requirements, combustors operating on coal must be designed to cope with liquid slag. Materials of construction must be able to withstand slag attack. If slag is to be rejected from the combustor proper, a suitable means for tapping the molten material must be incorporated into the design. Also, the interaction of seed and slag must be minimized to prevent excessive losses of seed.

Due to the electrical generating nature of the MHD channel, the combustor will have a high potential, which in the case of commercial-scale units may be 25,000 to 35,000 volts. This results in the necessity of electrically insulating the combustor from all supports and feed lines (fuel, oxidizer, seed, cooling water), as well as from the slag rejection system.

Combustors designed for MHD applications may consist of one or more stages. When burning natural gas or fuel oil, there is no incentive to use other than a single-stage configuration. With these fuels, satisfactory performance has been obtained in experimental single-stage combustors operating under predominantly plug flow conditions. When burning coal, the selection of a combustor configuration will be dictated by technical and economic considerations with respect to the level of slag carryover that is permissible in downstream portions of the power plant.

The presence of slag in an MHD plasma has a negative effect on plasma conductivity, results in loss of seed material, and may seriously affect the operation and integrity of downstream components. While available evidence suggests that low slag carryover from the combustor is desirable, it is not possible at present to say what constitutes a tolerable level of carryover. Depending on the combustor design chosen, as much as 100 percent or as little as 10 percent of the mineral matter in the coal will pass through the MHD generator and be deposited or collected in downstream equipment. The fundamental differences in combustor design that most strongly affect the degree of slag rejection achieved are discussed below.

Single-Stage Coal Combustors

Single-stage combustors offer the advantage of simplicity of design and operation, and lower cost relative to multistage combustors; also, heat losses will probably be lower in single-stage units. They may operate with 100 percent slag carryover, or with partial removal of molten ash from the combustor proper.

If no slag is rejected from the combustor, a method must be developed to remove slag from the combustion gases downstream of the generator to avoid damage to other plant components. To achieve this without significant seed loss represents a major technical problem. An advantage of this mode of operation, however, is that the difficulty of tapping slag from a combustor at high pressure, temperature, and voltage is avoided.

In a single-stage combustor operating at temperatures in excess of 2700 K (4400°F), a major portion of the coal mineral matter will appear as vapor in the plasma*. Hence, the amount of liquid slag that can be tapped from the combustor proper will be limited. Also, there will be some degree of seed loss to the tapped slag in addition to that lost by reaction with slag carried over from the combustor. Contact of seed and slag in the combustor could be avoided by injecting the seed in a separate chamber following the combustor. However, this would lead to additional system heat losses.

Two-Stage Coal Combustors

In a two-stage coal combustor, slag rejection levels approaching 90% are possible. In such a system, the first stage is operated as a coal gasifier at temperatures ranging from 2200 to 2300 K (3500-3700°F). At these temperatures, very little of the coal slag is vaporized, and the bulk of the liquid slag can be separated from the gas using a first stage designed similar to a conventional cyclone combustor. The gas produced in the first stage is burned in the second state where seed is injected.

Operation of a two-stage combustor is more complex than in the case of a single stage unit. Additional high-temperature air lines, controls, and instrumentation are required. It is also likely that thermal losses will be somewhat higher in a two-stage system because of added system surface area.

Multistage Coal Combustors

Many conceptual studies of multistage MHD combustion systems have been reported in the literature[21-26]. Several of these systems offer potential slag rejection levels in excess of 95 percent. In general, the systems are highly complex, and represent novel technology that must be further developed before their feasibility is ascertained.

B. Current MHD Coal Combustor Development Programs

Pittsburgh Energy Research Center

Combustor development work at PERC is presently focusing on a two-stage design. Studies are being conducted with an atmospheric-pressure vertical cyclone that represents the first stage of a two-stage combustion system. Major objectives of the program include: 1) evaluation of cyclone combustors operating under fuel rich conditions with coals of different ranks; 2) testing of high-temperature plasma diagnostic techniques; 3) studies of seed-slag interactions; 4) evaluation of materials; and 5) development of techniques for controlling nitrogen oxides emissions. The size of the facility, and its atmospheric-pressure operation, allow rapid and inexpensive changes to be made in hardware design thereby permitting several design options to be tested during short periods.

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*For example, in burning Pittsburgh seam coal (10% ash) with 100% of stoichiometric air at 8 atm, thermodynamic calculations indicate that about 40% of the slag is vaporized at 2800 K, and 75% is vaporized at 3000 K.

During the past year, three different cyclone configurations were evaluated. Tests were carried out at coal feed rates ranging from 0.01 to 0.03 kg/s, oxidizer/fuel ratios ranging from 55 to 110 percent of stoichiometric, and (vitiated) oxidizer temperatures of 1100-1360 K (1500-2000°F). Primary emphasis has been placed on optimizing cyclone performance with respect to slag rejection and carbon conversion. A Montana Rosebud seam coal has been used in most of the tests.

The tests conducted thus far indicate that coal size consist plays a major role in determining slag rejection and carbon conversion. Slag rejection rates as high as 90 percent and carbon conversions greater than 98 percent have been achieved under substoichiometric conditions.

A separate facility has been constructed at PERC to test MHD combustors (nominal 5 MW thermal input) at pressures up to 8 atmospheres. The facility is capable of continuous operation and includes equipment for coal pulverizing, drying, conveying, and feeding under pressure.

A two-stage combustor has been installed in the facility. The first stage, a vertical cyclone, will be operated as a coal gasifier. The second stage is a gaseous fuel combustor.

The maximum total flow rate attainable in the facility is 1.7 kg/s. An air preheat temperature of 1200 K (1700°F) will be possible, with provisions available for vitiated air (or O_2-enriched air) at temperatures up to 1866 K (2900°F). Initial tests will be conducted at 6 atm pressure, a coal thermal input of 2-3 MW, and a total mass flow of 1.2 kg/s.

The objectives of the test program are similar to those indicated for the atmospheric-pressure facility. However, the operation is more complex due to the high pressures involved and the two-stage configuration. Also, an instrumented test section, designed and supplied by Avco Everett Research Laboratory, will be installed downstream of the second-stage combustor to permit measurements of plasma properties in time and space including temperature, pressure, velocity, and electrical conductivity.

Component Development and Integration Facility (CDIF)

The Energy Research and Development Administration is presently constructing a major MHD test facility in Butte, Montana. The Component Development and Integration Facility (CDIF) is designed to permit long duration testing of major components required in commercial MHD plants of the future. The test program will allow resolution of many technical problems associated with direct use of coal, and will provide valuable scale-up data for the design of a complete prototype MHD power plant. Initial testing at the CDIF is expected to begin in late 1978.

The facility will have a thermal rating of 50 MW; the fuel thermal input will be 38 MW and the balance will be due to sensible heat of the oxidizer. Total mass flow rate will be 9.6 kg/s. Initial tests will be conducted using vitiated air at 1866 K (2900°F); high-temperature regenerative air heaters will be added at a later date. The test train will be operated at pressures ranging from 3 to 10 atmospheres.

The first coal combustor tested will be supplied by the Pittsburgh Energy Research Center. The combustor will be a two-stage design similar to the unit presently being tested at PERC.

University of Tennessee Space Institute (UTSI)

A new MHD test facility is being constructed at UTSI in Tullahoma, Tennessee, and is expected to be operational in 1979. The purpose of the facility, in addition to generator development, is to provide design data for single-stage coal-fired combustors. Problems associated with coal handling, downstream slag removal, and seed-slag separation will be investigated. A major objective is to determine the effects of long-duration operation on component performance.

Two plug flow combustors will be tested. One unit, with a mass throughput of 3.6 kg/s, will be capable of continuous operation. Total thermal input will be 23.7 MW (21.1 MW coal). Oxygen and vitiated air will be used as oxidizers. The combustor will operate at a pressure of 8 atm and a temperature of approximately 3000 K.

Short duration tests (several hours) will be conducted with a larger combustor having a mass throughput of 13.6 kg/s. Coal will provide 56.2 MW of the total thermal input of 66.8 MW. This combustor will also operate at a pressure of 8 atm and will generate a plasma at about 2800 K.

V. DISCUSSION AND CONCLUSIONS

Three different approaches to utilizing coal to reduce our dependence on natural gas and foreign oil have been discussed. An attempt will now be made to assess the status of each of these technologies, and to determine their potential impact on our national energy supply situation.

Coal-Oil Slurry

There appears to be no technical reason why coal-oil slurry could not be utilized now in existing oil and/or gas fired boilers. Considerable success has been achieved in firing slurries in industrial units for short periods. Tests at PERC indicate that erosion and corrosion would not appear to be a problem in retrofitting industrial gas/oil boilers to fire a slurry.

Some additional research is required to better define the effects of coal rank, coal concentration, and coal particle size consist on combustion characteristics of slurries. The development of an effective, inexpensive stabilizer would greatly enhance the attractiveness of slurries; coal-oil mixtures could then be prepared in one location and transported as other liquid fuels are, thereby obviating on-site preparation of coal by the user.

In general, utilization of slurries in lieu of low-sulfur oil or natural gas will produce air pollution concerns. Particulate emissions will have to be dealt with, as will SO_2 emissions unless a low-sulfur coal is used. However, adequate particulate removal equipment is available, and effective flue gas desulfurization technology is being developed.

Wide spread utilization of coal-oil slurry by utilities could potentially produce a savings of about 500,000 bbl/day of fuel oil, based on 1975 oil consumption data*[35]. Considering only the fuel oil used by industry to generate steam in boilers[36], an additional 400,000 bbl/day could be conserved. If one also considers direct heating operations, it is likely that a total savings of fuel oil of well over one million bbl/day could be achieved.

It appears that the incentive for a particular industrial user to convert to coal-oil slurry will simply be to conserve oil supplies, or to have fuel available in the event of natural gas curtailments. At present the estimated cost of slurry per million Btu is nearly equivalent to that for fuel oil. However, should costs for foreign oil escalate (and assuming coal costs remain stable), use of coal-oil slurry could also provide a significant savings in fuel costs.

Solvent Refined Coal

SRC appears to be a very attractive fuel for utility and industrial applications. Problems in handling and burning SRC have been overcome, and the technology for producing SRC is close to being demonstrated on a commercial scale.

The use of SRC provides an alternative to flue-gas desulfurization which can be a significant consideration with respect to capital costs for a new coal fired power plant. Since the properties of SRC appear to be uniform regardless of the coal feedstock, economies in design and construction of new power plants can be achieved.

SRC could be used directly in many existing power plants which were designed for coal but are now burning low-sulfur oil to avoid the use of flue-gas scrubbers However, the major impact of SRC will be through its use in future (1985 and beyond) power plants which will undoubtedly be prevented from using natural gas or low-sulfur oil.

While the cost for producing SRC, or any coal-derived fuel is uncertain, it may well be competitive with fuel oil[37]. Costs, however, will likely become a secondary concern in future years when the choice is between an assured domestic supply of fuel on the one hand, and an uncertain foreign supply on the other.

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*Assuming 40% coal/60% oil slurry.

Coal Fired MHD Combustors

The attractiveness of MHD as an efficient, pollution-free process for converting coal to electricity provides a strong incentive for further development of this technology. Although some degree of success has been attained in the development of MHD combustors, a considerable amount of additional development work must be carried out before commercial-size units are a reality. Many uncertainties exist with respect to scale-up from present experimental information.

A commercial MHD power plant of, say, 2000 MW (thermal) capacity will have a combustion products mass flow rate of about 700 kg/s, and will operate at a peak pressure of about 8-10 atm. However, experimental combustors have operated at mass flow rates in the range of 0.2 to 3 kg/s. In general, experiments have been conducted at pressures considerably below that required in commercial applications.

In a base-load MHD power plant, a single combustor (with some amount of turndown capability) would probably be most desirable. Additional data must therefore be acquired to formulate reliable scaling laws; this can only be accomplished by construction and operation of combustors considerably larger than those tested to date, yet still much smaller than a commercial unit. Key questions that must be answered include the effect of scale-up on combustion stability, efficiency, and heat losses.

It may be feasible to limit the magnitude of scaling required if one considers the use of multiple combustors in a commercial plant. Such an arrangement provides an added degree of flexibility in terms of turndown capability. However, it is likely that the use of multiple combustors will result in greater heat losses than those associated with a single large combustor. In addition, the complexity of the total combustion system is increased substantially due to the need for additional controls, hot-air piping, and fuel feed systems; and problems related to combustion stability may be magnified. Even if the use of a multiple-combustor system were practicable, the size of the individual units would be substantially greater than combustors that have been operated to date, and the need for further testing on a larger scale would still be necessary.

Aside from concerns directly related to the combustion process, there are additional issues that must be addressed in the development of commercial MHD combustion systems:

1) reliable, long-term operation of MHD combustors must be demonstrated. Typical continuous tests conducted thus far have been of short duration (several hours or less);

2) reliable and durable systems for feeding large quantities of high-temperature air, fuel, and seed into pressurized combustors must be developed. The uniform injection of coal at rates of about 65 kg/s (2000 MW thermal) represents a particularly challenging problem;

3) techniques for electrically isolating a high-temperature combustor from feed lines, cooling water lines, slag rejection system, and supports must be developed;

4) optimum coal-fired combustor configurations must be established; this will be governed primarily by the percentage of ash deemed desirable to be carried over through the generator and the downstream portions of the system. Single-stage combustors are likely to provide relatively poor slag rejection, but have lower heat losses than multistage combustors, whereas two- and three-stage combustors can probably operate with slag rejection rates approaching 90%;

5) methods for minimizing heat losses from large-scale combustors should be explored, such as air-cooling of combustor walls or transpiration cooling of combustor refractories.

Many of the items discussed above are being addressed in programs currently underway in the United States and the Soviet Union, or will be as new test facilities become operational in the near future.

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SESSION IB - STRATEGY AND APPROACH TO SPONSORED R&D

SESSION CHAIRMAN: ANDREJ MACEK, U.S. ERDA

While it is realized that the massive projected increase in utilization of coal (more than 50% between 1976 and 1985) cannot be accomplished merely by infusion of federal funds, federally sponsored R&D will clearly be instrumental for this attainment. This session provides information from top officials of the three principal federal agencies sponsoring R&D in this area: ERDA, Bureau of Mines, and EPA. These papers cover what the Government is doing, and what it intends to be doing in the future, to implement clean combustion of coal.

A significant amount of research is also being sponsored by the Electric Power Research Institute, but they were not able to send a representative to this conference.

STRATEGY IN COAL PREPARATION RESEARCH PLANNING

by

W. E. Warnke
Coal Preparation Research Manager
U.S. Bureau of Mines

Good evening to all of you. Because we've just eaten dinner there is some danger of being lulled to sleep. As it happens, I don't have any visual aids or funny stories to tell as an aid in maintaining your attention but I will cite some percentage numbers that may pique your interest. Those of you who are familiar with RI 8118 on sulfur removal potential may be pleasantly surprised by these numbers tonight.

Let's not belabor the issue of increasing the utilization of coal. The necessity of replacing gas and petroleum with coal has been eloquently discussed by earlier speakers. So, let's talk about the four options as I perceive them in burning more coal. Then, I'll outline the Bureau of Mines strategies in planning a five year research program for coal preparation.

The electrical utility industry and other industries requiring large amounts of fossil fuel have four options for burning coal in compliance with sulfur dioxide emission standards. The first is the use of flue gas scrubbers. Costs of scrubbing sulfur oxides from flue gases range from $10 per ton of coal burned to $19 per ton depending on how the capital costs are amortized and who does the cost evaluating. For lack of a better number, let's assume these costs are $15. Flue gas scrubbing also is an energy user because limestone must be mined and transported to the utility plant and perhaps as much as 5 percent of the energy derived from burning coal is used to drive the scrubbing system.

Transporting low sulfur subbituminous coal from Wyoming and Montana to Eastern and Southern utilities is the second option. Unit train costs are about one cent per ton mile so a haul of 1200 miles adds $12 to the costs of a low grade fuel averaging less than 20,000,000 Btu's per ton. Unfortunately, much of the subbituminous and lignite coals contain one percent or more sodium which causes the ash minerals to slag at temperatures of about 2000 degrees F. Boilers designed to burn the bituminous coals of the East need retrofitting to avoid slag buildup on heat transfer surfaces. The retrofitting is expensive and decreases boiler efficiencies. I've not considered coal slurry pipelining as a means of moving coal from mine to utility for the simple reason that pipelines may not be used for reasons other than economics. If costs of installing a coal slurry pipeline escalate like the Alaskan oil line, the pipelines may not be competitive with unit trains.

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The third option is cleaning high sulfur Northern Appalachian and Midwestern coals to acceptable sulfur levels. This option is restricted to cleaning coals from these two regions because the Mississippi Basin and Northeastern regions of this country represent areas of high demand for steam coal. According to a study conducted by the Bureau of Mines on the sulfur removal potential of 227 samples taken from major bituminous seams in the states of Pennsylvania, Northern West Virginia, Ohio, and Maryland, 100 samples could be beneficiated or burned without any beneficiation as compliance coal. The mean Btu recovery was 75 percent. Coals from the Midwestern region are generally higher in both pyritic and organic sulfur than Eastern or Southern coals. Therefore, it was not at all surprising to learn that only 11 of the coals sampled in the Midwestern region could be beneficiated to compliance levels of sulfur with a mean recovery of 64.5 percent. The results of sink/float tests on 455 samples of coal from throughout the United States show that 42 percent can be burned as run-of-mine coal or can be beneficiated to meet compliance sulfur levels. Mean Btu recovery of these 192 coals was 83.6 percent. These washability tests simulated current washing practices in which only pyritic sulfur is removed.

Costs of cleaning coal by some form of physical separation to remove the pyrite and ash varies from about $2 per ton for the more simple flowsheets to $6 to $7 per ton for the more complex flowsheets. The latter includes equipment for fine grinding, flotation cells, thickeners, filters and dryers.

If we plan to use the 58 percent of the coals that are not amenable to conventional cleaning technology, then we must develop new physical cleaning technology and in some cases, combine it with chemical desulfurization. Bechtel Engineering Corporation recently completed an evaluation of six chemical cleaning processes. Although several of the six removed some organic sulfur, none of the six appeared promising. Costs for the entire process including crushing, grinding, chemical processing and compaction of the fine clean coal, ranged from $18 to $20 per ton. The Bureau of Mines has reservations about these processes for the simple reason that the costs equal or exceed flue gas scrubbing costs. We are investigating several other chemical processes but Richard Killmeyer of the Bureau's Coal Preparation Laboratory will discuss our plans later on another day.

The fourth option mentioned earlier is a combination of coal cleaning and scrubbing. If a coal can be partially desulfurized by a physical process costing $3 per ton or so and the coal burned with about 1/3 of the flue gases going to a scrubber, the combined costs may be less than scrubbing alone. There is no hard and fast rule on the amount of sulfur in the run-of-mine coal, the cost of partially desulfurizing by physical cleaning and the ratio of unscrubbed flue gas to scrubbed flue gas. Each coal would require testing to determine the amount of sulfur removed by cleaning and the amount of the gases requiring scrubbing to meet the 1.2 pounds of sulfur dioxide standard. Hoffman-Muntner Associates prepared a study on combined cleaning-scrubbing costs for the Bureau. This study which is being published for public dissemination, outlines 12 combinations of coals, flowsheets and scrubbing systems. The costs of combined cleaning/scrubbing are compared to scrubbing alone.

We in the Bureau of Mines believe that cleaning the coal prior to combustion is the most attractive of the four options both economically and environmentally. When coal is cleaned to remove pyrite, a major portion of the more objectionable trace elements such as cadmium, lead, arsenic, and mercury are also removed. These elements are generally not removed by present day scrubbing processes which means they are redistributed as fallout from the emitted flue gases. Furthermore, wastes from washing plants can be dewatered and used as stable landfill material in an environmentally acceptable manner, whereas sludge from scrubbing plants is more difficult to impound or store without jeopardizing the environment. And, from an economic standpoint, if you'll excuse reference to the obvious, a $6 or $7 per ton cost for sophisticated cleaning processes is considerably less than the $15 scrubbing costs.

The Bureau recognizes that current coal washing practices are inadequate in removing finely disseminated pyrite and remove no organic sulfur. Consequently, the Bureau's program is heavily oriented towards fine grinding to obtain optimum liberation of pyrite and with emphasis on flotation or high gradient magnetic separation to remove most of the pyrite without sacrificing Btu recovery. The Bureau is also concerned with chemical desulfurization of coal as a means of removing organic sulfur. When coal was selling for 10-15 cents per million Btu's, the type of projects the Bureau authorized was constrained by the funds available for research and by the costs of the processes under investigation.

Our coal preparation research program in the past consisted of small projects designed to achieve engineering advancements to the state-of-the-art. We didn't have funds for large projects and couldn't afford much risk. Virtually overnight the game changed from penny ante to a sky-is-the-limit high roller game. This is not to imply that we're squandering funds on worthless ideas because the projects we fund are based on bench scale data and evaluated for technical feasibility. But the stakes are measured in billions of dollars annually to the consumers of electrical energy and so because of the stakes we can afford greater risks in the hope of developing a process for cleaning Eastern coals.

Perhaps I'm too optimistic but I believe that physical coal cleaning technology will be developed so a much larger percentage of the coals in the Eastern half of the United States can be cleaned to compliance levels. I'm also optimistic about increasing significantly the Btu recovery in the clean coal product. That, in essence, is the Bureau's strategy. We are convinced that both physical and chemical coal cleaning deserve more consideration by policy and decisionmakers in industry and government as very attractive alternatives to scrubbing or transporting coal long distances.

STRATEGY AND APPROACH TO ERDA RESEARCH AND DEVELOPMENT ON CLEAN COMBUSTION OF COAL

Dr. S. William Gouse
Deputy Assistant Administrator for Fossil Energy
U.S. Energy Research and Development Administration

As the population and economy of the United States continue to grow, the need for energy will increase. In 1970 the U.S. used about 67 quads; in 1976 about 74, and projections for the year 2000 range from less than 100 to over 150 quads, or more than twice the 1976 level.

Although conservation and new end-use technologies can limit the amount of energy we will need, society will still need large amounts of energy to support our growing and productive economy. This energy can come from a variety of forms, including solar, nuclear, and new and conventional solid, liquid and gaseous fossil fuels.

The main issue for RD&D planning is not how many quads we will need in any future year, but how we will choose to provide them.

Today about 75 percent of our energy comes from petroleum and natural gas, and we import some 40 percent of our liquid fuels. There is a great deal of uncertainty regarding the future availability and cost of those fuels. Known reserves are being depleted rapidly and new discoveries have not kept pace with rising demand. Indeed, there is some question as to how long the earth's total recoverable resources could support historically rising demand for oil and gas. All studies indicate that synfuels in various forms will be required in the future.

We need appropriate action now to insure adequate supplies of energy at reasonable prices to preserve our national security and provide reasonable lifestyles.

There is no magic solution. Any specific approach to the problem has its own advantages and disadvantages and these are often perceived differently by different groups. There are many complicating factors, each with its own degree of uncertainty and each interacting with all the others, often in unpredictable and counter-intuitive ways.

As an example of this interaction, consider new home heating systems. A perceived supply problem in natural gas could push electric heating, even though that would require considerably more primary energy.

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The complexity of the problem makes it difficult to determine the "best" solutions. The first part of the fossil energy strategy is to define alternative ways to meet future energy service requirements in terms of social, institutional and economic consequences. The second is to provide the information to stimulate a productive national debate, which we hope will lead to a consensus on acceptable alternatives. Finally, we seek to conduct an R,R&D program that will clarify issues and insure that an effective number of viable alternatives is available.

There are several dimensions to the energy picture, and that fact accounts for much of the complication. Two of the most basic dimensions are the energy resources and the activities required to use them. These are effectively related by the Reference Energy System.

Reference Energy System, Year 1985 — With the NEP

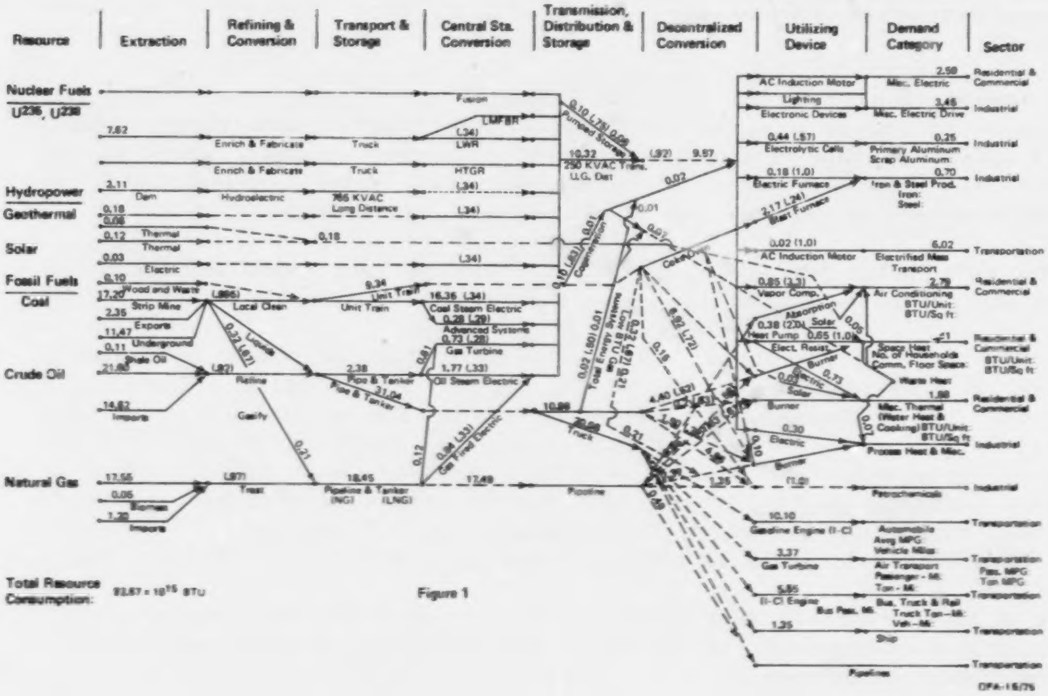

Resource
Extraction
Refining & Conversion
Transport & Storage
Central Sta. Conversion
Transmission, Distribution & Storage
Decentralized Conversion
Utilizing Device
Demand Category
Sector
Nuclear Fuels U235, U238
Hydropower
Geothermal
Solar
Fossil Fuels
Coal
Crude Oil
Natural Gas
Residential & Commercial
Industrial
Transportation
Total Resource Consumption: 82.67 × 10^15 BTU
OPA-16/76

Figure 1

The major energy sources are listed down the left-hand side and include nuclear, hydro, geothermal, solar, and the fossil fuels. The activities listed across the top include extraction, refining and conversion, transport, distribution and use. Conversion can be both centralized and decentralized.

The Reference Energy System, by identifying both service demand and utilizing device, permits the implicit consideration of conservation and efficiency improvements. This system can help us consider alternative pathways. Once the potential demands are estimated and various sets of resources and use technologies identified, we can determine various resource mix requirements. This forms a standardized basis for comparison in these two dimensions.

Fossil Pathways

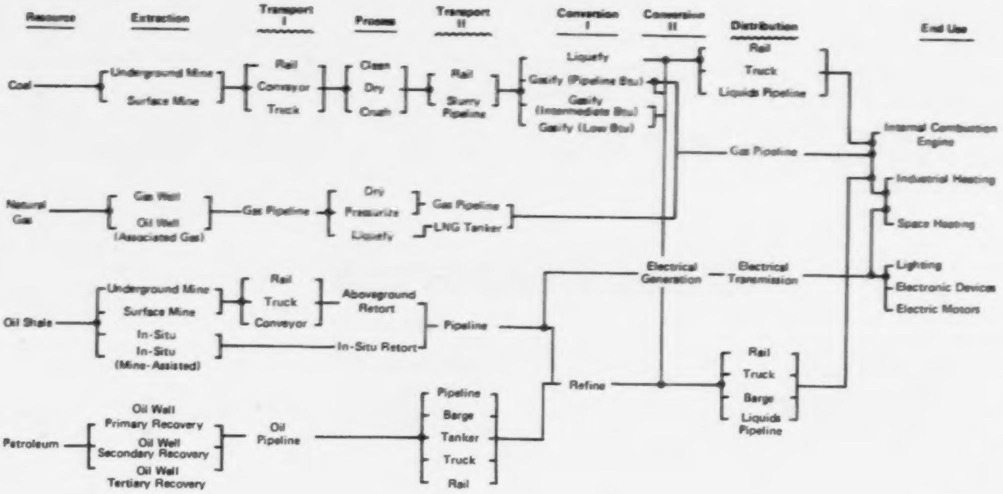

Resource
Extraction
Transport I
Process
Transport II
Conversion I
Conversion II
Distribution
End Use
Coal
Underground Mine
Surface Mine
Rail
Conveyor
Truck
Clean
Dry
Crush
Rail
Slurry Pipeline
Liquefy
Gasify (Pipeline Btu)
Gasify (Intermediate Btu)
Gasify (Low Btu)
Rail
Truck
Liquids Pipeline
Gas Pipeline
Internal Combustion Engine
Industrial Heating
Space Heating
Natural Gas
Gas Well
Oil Well (Associated Gas)
Gas Pipeline
Dry
Pressurize
Liquefy
Gas Pipeline
LNG Tanker
Electrical Generation
Electrical Transmission
Lighting
Electronic Devices
Electric Motors
Oil Shale
Underground Mine
Surface Mine
In-Situ
In-Situ (Mine-Assisted)
Rail
Truck
Conveyor
Aboveground Retort
In-Situ Retort
Pipeline
Refine
Rail
Truck
Barge
Liquids Pipeline
Petroleum
Oil Well Primary Recovery
Oil Well Secondary Recovery
Oil Well Tertiary Recovery
Oil Pipeline
Pipeline
Barge
Tanker
Truck
Rail
• Option points

Figure 2

Within fossil energy there are four major resources--oil, gas, coal and shale. Those resources can, via alternative pathways, meet end-use needs for all solid, liquid and gaseous fuels.

I should point out that exploration, although not shown here, is a major activity, particularly for oil and gas.

Coal Resources

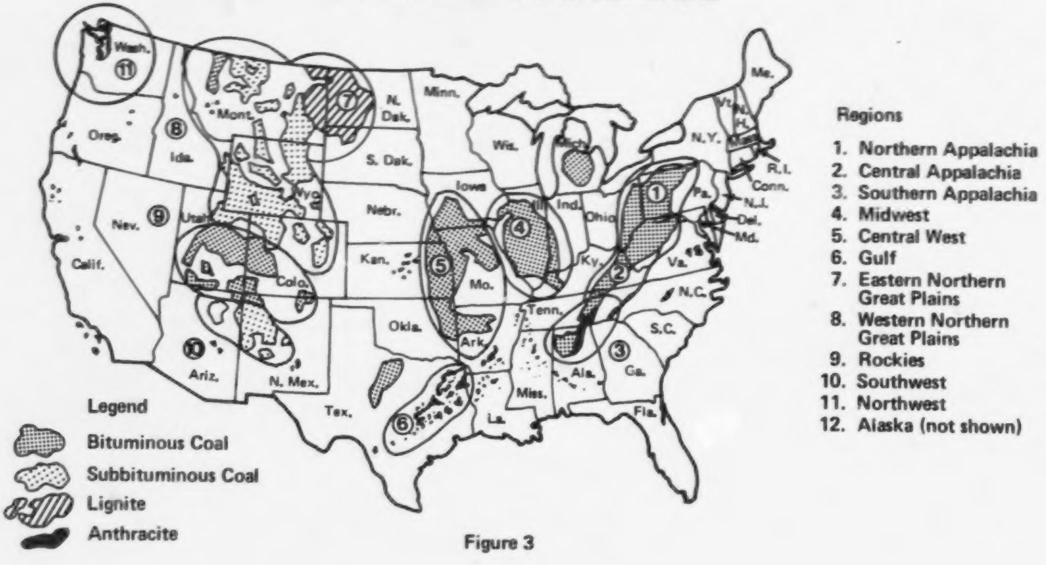

Wash.
Oreg.
Calif.
Nev.
Ida.
Mont.
Wyo.
Utah
Colo.
Ariz.
N. Mex.
N. Dak.
S. Dak.
Nebr.
Kan.
Okla.
Tex.
Minn.
Iowa
Mo.
Ark.
La.
Wis.
Ill.
Mich.
Ind.
Ohio
Ky.
Tenn.
Miss.
Ala.
Ga.
Fla.
S.C.
N.C.
Va.
Pa.
N.Y.
Me.
Vt.
N.H.
Mass.
R.I.
Conn.
N.J.
Del.
Md.
①
②
③
④
⑤
⑥
⑦
⑧
⑨
⑩
⑪
Legend
Bituminous Coal
Subbituminous Coal
Lignite
Anthracite
Regions
1. Northern Appalachia
2. Central Appalachia
3. Southern Appalachia
4. Midwest
5. Central West
6. Gulf
7. Eastern Northern Great Plains
8. Western Northern Great Plains
9. Rockies
10. Southwest
11. Northwest
12. Alaska (not shown)

Figure 3

Within each major category, there are wide variations as to the nature, characteristics and location of the resources. This figure shows where the nation's major coal deposits are found, as well as the location of coal by rank from peat and lignite and peat through bituminous and anthracite.

An additional complication concerns the fact that coal is not a single material; rather, it is a family of related materials, differing widely in heat content, contaminates (such as sulfur and ash) and physical properties (such as caking and hardness). These characteristics greatly affect their use. Processes for coal conversion do not work equally well on all coals. It is not useful to consider liquefaction of anthracite.

Shale Resources

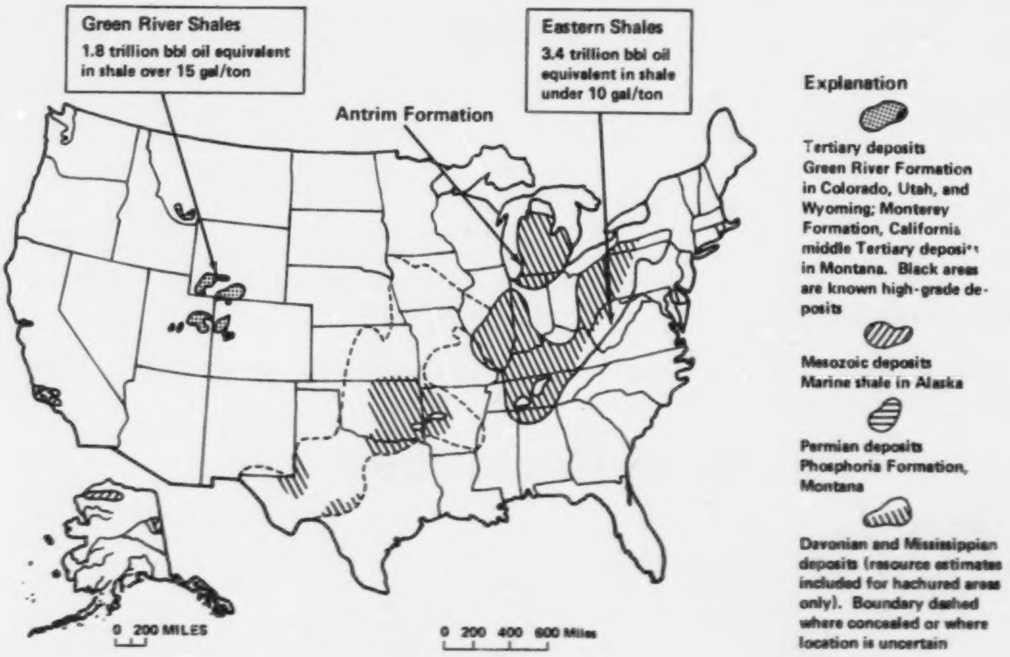

Green River Shales
1.8 trillion bbl oil equivalent in shale over 15 gal/ton
Eastern Shales
3.4 trillion bbl oil equivalent in shale under 10 gal/ton
Antrim Formation
Explanation
Tertiary deposits Green River Formation in Colorado, Utah, and Wyoming; Monterey Formation, California middle Tertiary deposits in Montana. Black areas are known high-grade deposits
Mesozoic deposits Marine shale in Alaska
Permian deposits Phosphoria Formation, Montana
Devonian and Mississippian deposits (resource estimates included for hachured areas only). Boundary dashed where concealed or where location is uncertain
0 200 MILES
0 200 400 600 Miles

Figure 4

This figure on shale resources shows the great variability in the location and characteristics of the shale resource. Western shales have a high potential for liquids production but are far from prime markets. Eastern shales have promise for both gas and liquids production and are near demand centers. A similar situation exists for oil and gas.

Heavy Oils And Tar Sands

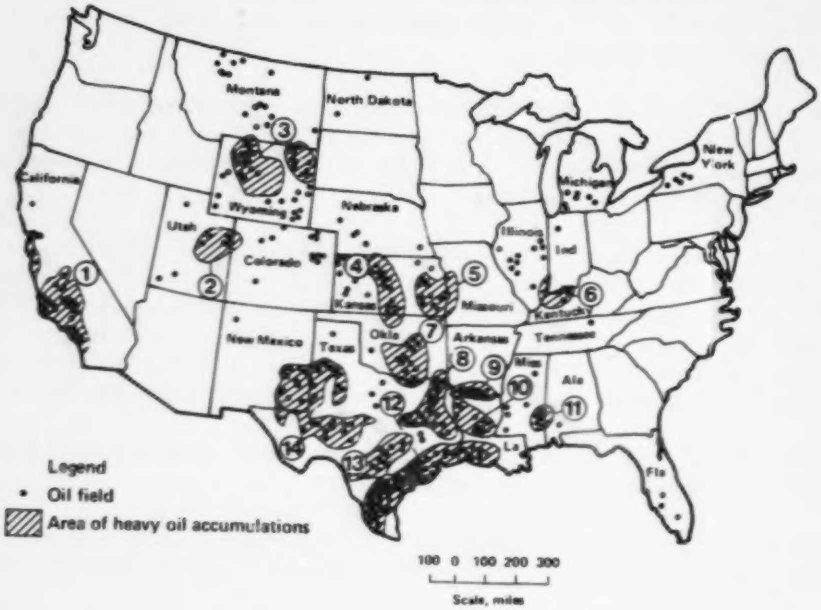
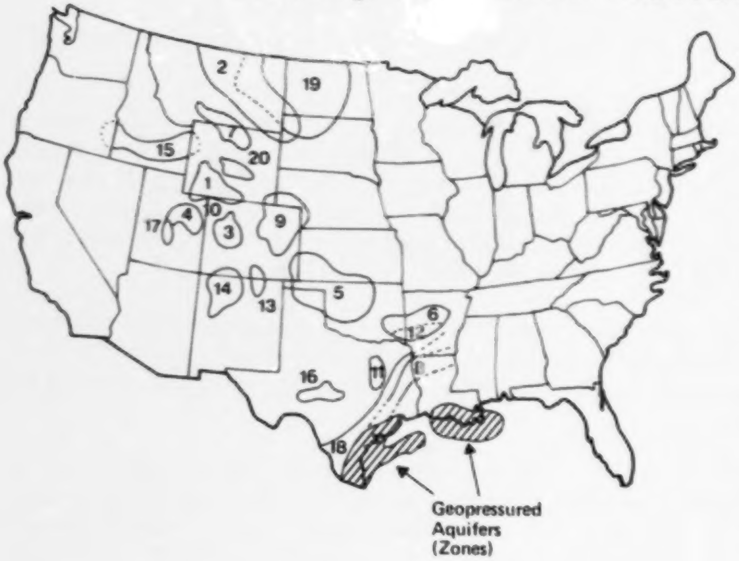

Montana
North Dakota
California
Utah
Wyoming
Nebraska
Colorado
Kansas
New Mexico
Texas
Okla
Missouri
Arkansas
Illinois
Ind
Michigan
Kentucky
Tennessee
Miss
Ala
La
Fla
New York
1
2
3
4
5
6
7
8
9
10
11
12
13
14
Legend
• Oil field
▨ Area of heavy oil accumulations
100 0 100 200 300
Scale, miles

Figure 5

Low Permeability Sandstone Areas/ Geopressured Zones


1
2
3
4
5
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9
10
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12
13
14
15
16
17
18
19
20
Geopressured Aquifers (Zones)

1. Greater Green River Basin
2. Northern Great Plains Province
3. Piceance Basin
4. Uinta Basin
5. Anadarko Basin
6. Arkoma Basin
7. Big Horn Basin
8. Cotton Valley Trend
9. Denver-Julesburg Basin
10. Douglas Creek Arch
11. Ft. Worth Basin
12. Ovachita Mountains Province
13. Raton Basin
14. San Juan Basin
15. Snake River Downwarp
16. Sonora Basin
17. Wasatch Plateau
18. Western Gulf Basin
19. Williston Basin
20. Wind River Basin

Figure 6

Figure 1 can be examined again to explain much of our program content. For example, the oil and gas program focuses on enhanced recovery techniques; shale focuses on in situ conversion; and coal conversion on producing liquids and gases.

In the industrial sector, for example, we are concerned with the need for process steam, feedstocks, electrical and mechanical energy, indirect heat and direct heat. Each of these represents a demand for liquids, gaseous and solid fuels.

Transportation, with its very large requirement for liquids, is an excellent sector to illustrate the available programs and pathways. The obvious way to satisfy these needs is through petroleum--off shore, enhanced recovery, etc. But coal and shale may also produce liquid fuels. However, coal liquids are chemically different than shale liquids. Coal could make gasoline while shale could produce jet fuels.

Boiler fuels from all four resources can meet electricity utility demands, but the emphasis is on coal.

End use devices can offer compromises with supply technologies. For example, we can heat homes with coal through the following paths:

- Coal to SNG, conventional gas furnaces
- Coal to SNG, gas heat pump
- Coal to synthetic liquids, conventional oil furnaces
- Coal to electricity, scrubber, resistence heat or heat pump
- Coal to SNG to electricity, resistence or heat pump
- Coal to synthetic liquids to electricity, resistence or heat pump

Because the energy system is so pervasive and complex, the two-dimentional matrix is not sufficient. There is another important dimension to the problem. Another dimension involves constraints to applying each supply and end-use technology, I have listed eight of the most obvious ones here, representing the areas in which there must be compromises in selecting R&D activities for Federal support.

Each of these must be understood in terms of its consequences and the manner in which it interacts with all others. For example, any decision on environmental controls will certainly have social and economic consequences.

The fourth dimension is time. We are facing the transition from a normal oil and gas-based economy to one based on renewable or non-depletable resources. We aim to use coal, and other conventional fossil resources to get us through this transition with minimum disturbance to society.

Constraints

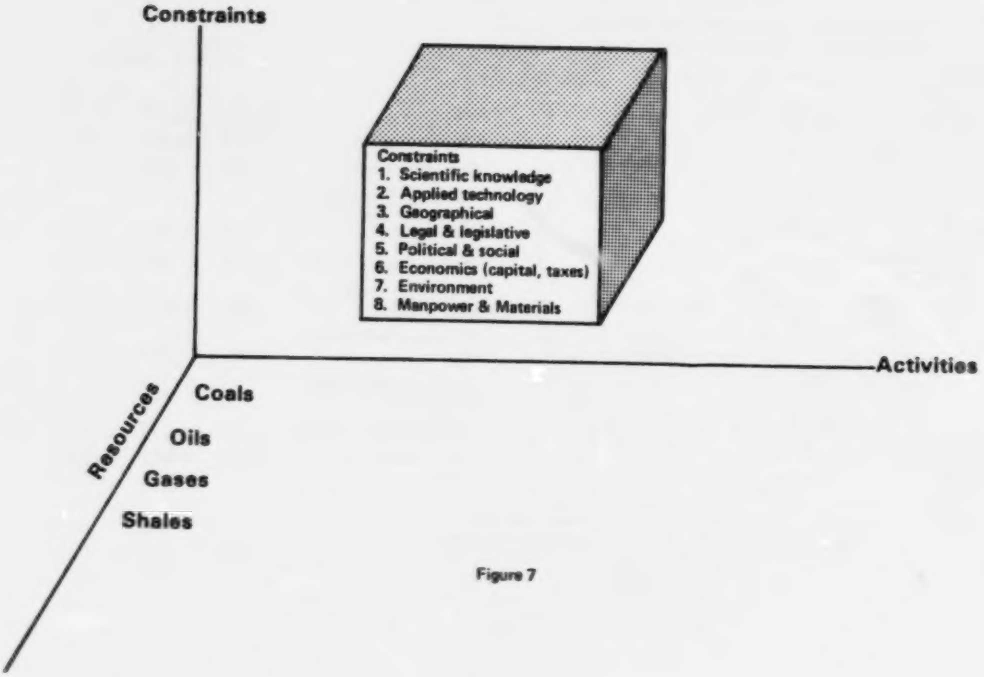

Constraints
Constraints
1. Scientific knowledge
2. Applied technology
3. Geographical
4. Legal & legislative
5. Political & social
6. Economics (capital, taxes)
7. Environment
8. Manpower & Materials
Activities
Resources
Coals
Oils
Gases
Shales

Figure 7

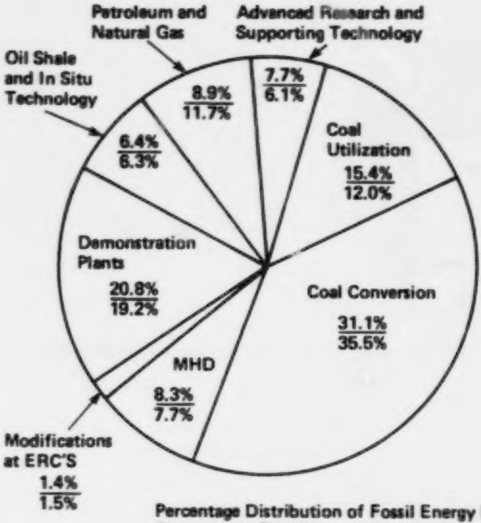
In our decisions, we must recognize that we are being pushed by the decreasing availability and increasing cost of oil and gas. We must also recognize that this situation will become more urgent with time, especially, if we do not act now.

Time is important because all technologies are not in the same state of readiness. Because of several fossil energy options for each end-use requirement plus other ERDA programs, all technologies may not have an implementation window. Careful study of potential market penetration must be used as an aid to setting R&D priorities as well as other things mentioned thus far.

With this background and overview let us concentrate on the Fossil Energy program, which in addition to clarifying social issues, seeks to develop the quantities we need at acceptable economic, social and environmental costs.

We want to increase supplies in the near term for all markets using liquids and gaseous fuels, as well as for electric power. The appropriations and activities for coal, oil, gas and oil shale differ. The reason concerns the fact that because of the unequal levels of private R&D investment for the different fossil fuels, the state of development of conversion and extraction technologies varies considerably. You will note that the requested FY 78 Budget for Fossil Energy is $656.9 million and coal receives almost 82 percent of that amount.

Fossil Energy Budget Estimates-Distribution of Funds



	Budget Authority (Dollars in Millions)		
	FY 77	FY 78	Increase Decrease
Coal Conversion	$150.3	$233.3	$+83.0
Coal Utilization	74.4	79.1	+4.7
Advanced Research and Supporting Technology	37.1	40.3	+3.2
Demonstration Plants	100.3	125.9	+25.6
Magnetohydrodynamics (MHD)	40.0	50.5	+10.5
Petroleum and Natural Gas	43.2	76.7	+33.5
Oil Shale and In Situ Technology	31.0	41.5	+10.5
Modifications at ERC'S	6.9	9.6	+2.7
Total	$483.2	$656.9	$+173.7

Percentage Distribution of Fossil Energy Budget Estimates in FY 1977 and FY 1978 Shown as Follows:

FY 1977%
FY 1978%

Figure 8

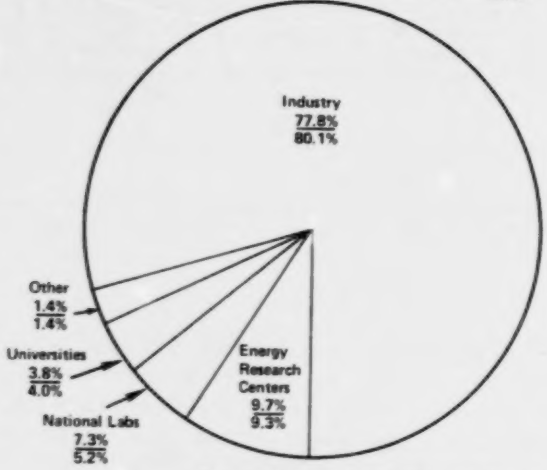
Thus our commitment to Fossil Energy, especially coal is great, because the resources are abundant. In total, they can supply all of the Nation's additional needs for over a century--more than enough time to develop technologies to exploit "inexhaustible" resources economically.

Our objective is to develop technologies that will have widespread applicaton by private industry. How do we go about this? Is ERDA/FE the main customer for the technology it helps create? The answer is no. At ERDA we feel that as the main producer or consumer of energy, the private sector is primary and the role of the Federal Government should be the supplementary one of sharing risks with private industry. Thus, the national needs we are charged to satify are felt and satisfied almost entirely in the private sector--by industry, commerce and individuals acting through the marketplace.

So in order to achieve our missions and goals, ERDA/FE seeks to (1) establish the appropriate policy and technical climate (with appropriate incentives, if needed) for private sector action; (2) share risks with private industry; and (3) support a complementary RD&D program to obtain necessary and timely information and to help stimulate the private sector. Thus, ERDA does not expect to be in the energy business. We have nothing to "sell." Our approach is to utilize federal funds so that the private sector will participate right from the start of a project with its own know how and financial resources. Indeed, we aim for industry to be involved in our programs every step of the way--as the major contributors of technical ideas and approaches and as the major beneficiaries of operating experience. Therefore, industry will be completely familiar with the problems as well as with the results and data. Such involvement will put our industrial partners as well as the industries themselves in an ideal position to decide whether to implement a new technology. In turn, we will be in an ideal position to know the obstacles--financial and otherwise--to overcome in order for the technology to be implemented.

This figure shows that industry receives the overwhelming percentage of the Fossil Energy Budget.

Distribution of Fossil Energy Funds



Percentage Distribution of Fossil Energy Budget Estimates in FY 1977 and FY 1978 Shown as Follows
FY 1977%
FY 1978%

Figure 9

Fossil Energy Budget Estimates Breakdown of Funds by R&D Agency Budget Authority
(Dollars in Millions)

	FY 1977	(% of Total)	FY 1978	(% of Total)
Energy Research Centers	$47.0	(9.7)	$60.9	(9.3)
National Laboratories	35.2	(7.3)	34.0	(5.2)
Universities	18.2	(3.8)	26.1	(4.0)
Industry	375.9	(77.8)	526.3	(80.1)
General Plant and Equipment, Construction, OSHA and Environment at Energy Research Centers	6.9	(1.4)	9.6	(1.4)
Total	$483.2		$656.9	

Figure 10

Industry is involved in the typical development sequence shown below.

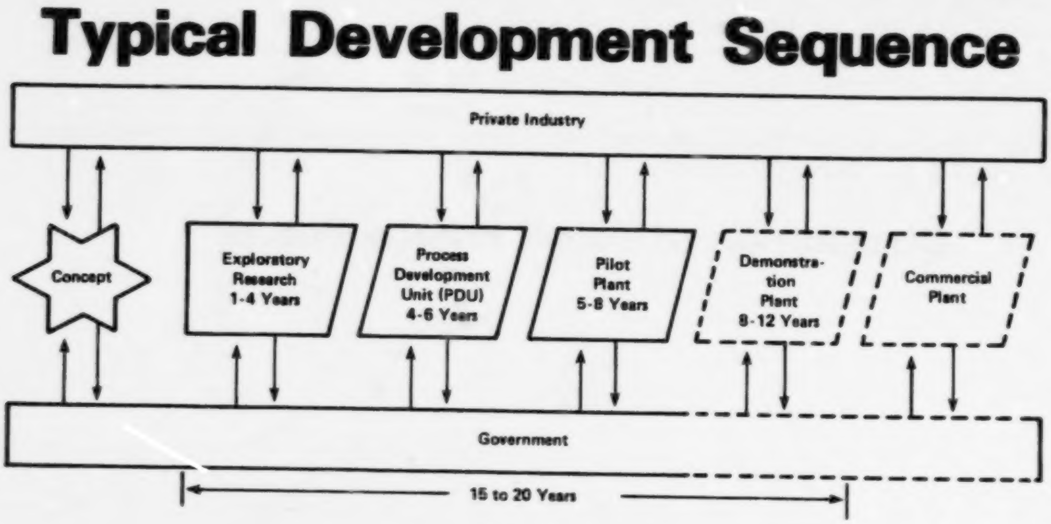

Typical Development Sequence
Private Industry
Concept
Exploratory Research 1-4 Years
Process Development Unit (PDU) 4-6 Years
Pilot Plant 5-8 Years
Demonstration Plant 8-12 Years
Commercial Plant
Government
15 to 20 Years

Figure 11

Each phase in the sequence involves scaling up to larger units, until in demonstration plants, the scale is large enough to provide firm data for cost estimates and design of commercial scale plants. Cost-sharing, while concentrated in the pilot plant and later phases, can also take place earlier. The time involved with each phase of development varies, depending upon the complexity of the process, project, scope, and resources applied.

Because in our accelerated program the phases overlap, the total development time is less than the sum of all phases. From laboratory to completion of demonstration plant operation is typically 15 to 20 years, and we evaluate technical feasibility of the concepts in each phase. Tentative economic evaluations start early in process development and continue through pilot and demonstration phases. We make more extensive economic evaluations with demonstration plants, as well as tentative environmental acceptability evaluations, water resources availability assessments, and environmental impact statements, as required.

There has been much talk about the possible need to start up whole new industries to implement new technologies. For some ERDA programs, such as solar energy, where the existing industrial base is small or nonexistent, this idea undoubtedly has some validity. Such is not the case for Fossil Energy where for years, a large base of existing companies has supplied the Nation's oil, natural gas, petrochemical and electricity needs. And, I might add, they have done that job well. For FE we need, not new industries, but technologies that either make sense in the marketplace, or which can be made to make sense by government initiatives, if there is sufficient public benefit from developing such technologies.

An example would be the synthetic liquids we will need in the future, derived from coal or from oil shale. There are barriers to their commercialization. For that reason, ERDA/FE has a commercial demonstration program, which we hope will resolve the uncertainties related to economic/environmental feasibility, socioeconomic impacts, resource requiremments, capital cost, financing and regulations. We need to resolve them in order to bring about the kind of broad-scale plant investment in the mid 1980's which we will need in order to achieve significant production in the 1990's.

At the same time we are developing Federal initiatives to build a synfuels industry, we are also working in the FE program to overcome the technical deficiencies in the current state-of-the-art. We do this through heavy investments in RD&D per se. We now support research in universities and industrial labs, and process development in corporations and laboratories. Pilot plant scale operations are underway in companies, in government and in independent centers. And ERDA/FE has an active and ambitious program to demonstrate at near commercial scale, promising second generation coal and shale processes developed by both industry and government.

Such activity pushes forward the frontiers of knowledge and advances the state-of-the-art. Our premises are: (1) Because of the regulatory and economic uncertainties I mentioned before, the private sector won't push as fast or as extensively as the national interest warrants. Thus, government provides incentives and the means for faster and more extensive progress; (2) As the state-of-the-art advances, a company can finish developing a commercially attractive process more easily. For patent reasons, a company may want to put its own stamp on a process, and thus, not adopt any we have sponsored in its entirety. But a company will have to contend with far less uncertainty than it does now (or did a year ago) and should have in hand the ingredients for success; (3) Many "systems" problems faced by new technologies can be understood and resolved only by actual trial (and some, by not too much error). Environmental impacts, effects of regulations, process bottlenecks, etc., are still most clearly identified and best dealt with in actual practice. Hence, our demonstration program aims to put the pieces together at a near-commercial scale to show potential users of the technology what applying it will involve; (4) The existence and scale of the program highlights an important technological area and focuses attention on it. Companies not funded by ERDA thus may also be induced to invest in a particular technology. Companies having undisclosed processes may have to advance them in contention. Researchers may be stimulated to work on related topics, once the area, as a whole, becomes "fashionable." For such spill-over benefits, the government need not pay directly; (5) The people involved in the program, in ERDA, in our Energy Research Centers, in industry, and in the universities, acquire knowledge and skills indispensible to the eventual largescale commercialization of new technology.

In our program, we also address, in several ways, the obstacle of economic risk of the R&D.

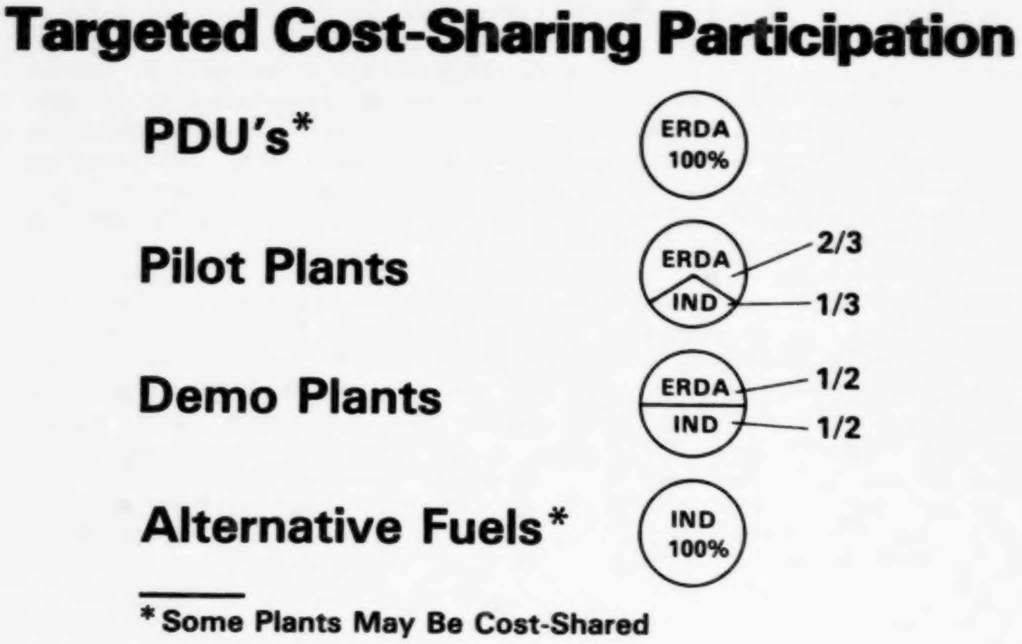


Figure 12

We pay 100 percent of the costs of basic and applied research and all the costs for the early stages of process development. We pay only about 2/3 of the costs for pilot plants, and about 1/2 of the costs for demonstrations. We do this partly because the costs rise as one moves along the development sequence. But more importantly, we do it to begin commercialization. Cost-sharing ensures that projects have merit by private standards and that industry will make a later commitment of other resources to protect its investment.

Because our industrial partners must put up a significant share of the funds, we expect them to make a significant share of the decisions about what and how to test. Thus, they bring their technical and marketing judgements to bear early. What will they learn from the project? Will the product sell? Will the process work? What will the product cost? We issue flexible Program Opportunity Notices or specific requests for proposals in areas that appear to warrant that scale of development. Companies then respond with detailed proposals specifying what they prefer to do. Because their stockholders' money is on the line, they must apply their best commercial insights and expertise.

As a result, the process development sequence ceases to be a straight path. Each stage, merges, modifies or drops components and adds new ones. We would be surprised if many proposed demonstration projects were direct lineal descendents of our process development units or pilot plants.

More generally, ERDA could find other ways to reduce economic risk besides cost-sharing, including loan guarantees, price supports and special tax credits for energy related investment.

No one fully knows the long-run impacts of these different approaches. We are studying some of them now and we need to look at others. We are studying one of them now and we need to look at others. We are studying, for example, projected market demands for the several forms of fossil energy and costs of advanced technologies. We are also looking at contingency plans and their impact on overall strategy and choice of federal role. We consider too, in selecting the Fossil Energy project "portfolio," how to balance the need for short-term, relatively sure "blue chips" against the need for near-to-mid term improved processes, moderate risks and potential breakthrough "high flyers."

In conclusion, I am optimistic that our Program can supply the fossil energy bridge to the next century if we can develop a real government private industry partnership. Such a partnership will clear away the roadblocks--environmental, price, regulatory and legislative--to bringing promising technologies into the marketplace. Conferences such as these help to find the path to innovation because we need new technology to solve our energy problems. We need entrepreneurship because whatever is developed needs to be brought to market, not bought by the government.

EPA R&D PROGRAM RELATING TO CONVENTIONAL COAL COMBUSTION

by

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The Clean Air Act Amendments of 1970 are the major driving force for control of air pollution from both new and existing combustion sources. The Act has a statutory requirement to achieve acceptable ambient air quality for the so-called criteria pollutants (Figure 1). Among these pollutants are sulfur dioxide and total suspended particulates which are essentially stationary source pollutants and nitrogen oxides which are generated by both stationary and mobile sources in roughly equal quantities. In addition, the Clean Air Act calls for the promulgation of New Source Performance Standards (NSPS) for a variety of polluting industries including coal-fired steam generators. Presently standards are on the books for control of sulfur dioxide, total suspended particulates and nitrogen oxides from coal-fired, oil-fired and gas-fired steam generators. The present NSPS for coal units, as well as typical uncontrolled emissions are included in Figure 1. As you can see, the present NSPS for coal-fired steam generators calls for approximately 70-80% control of sulfur oxide; for a high degree of particulate control (approximately 98%); and a moderate 30% control for nitrogen dioxide.

I must point out that there are certain changes which may occur both in terms of the Clean Air Act as well as some revised standards under the present Act which could have important impact on control technology requirements for fossil-fuel combustion units. First, the House and Senate have recently passed legislation which has gone to joint committee, calling for a best available control technology approach (BACT) for new coal-fired power plants insofar as sulfur dioxide and particulate pollution is concerned. Although the implementation details of this approach have not been worked out, and the final version of the Act has not yet passed both Houses, it appears that this change would require best available control technology for all new sources on both low- and high-sulfur coal applications eliminating the low-sulfur control option to meet sulfur oxide standards.

The second change might involve more stringent NSPS for coal-fired power plants than the existing standards (Figure 1). Revised standards are under consideration which could lead to more stringent control for sulfur dioxide, nitrogen oxides and total suspended particulates.

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STATUTORY REQUIREMENT TO ACHIEVE ACCEPTABLE AMBIENT AIR QUALITY FOR:

SO_2
STATIONARY SOURCES
TSP
NO_x
HYDROCARBONS
MOBILE SOURCES
CARBON MONOXIDE
PHOTOCHEMICAL OXIDANTS

STATUTORY REQUIREMENT TO MEET NSPS FOR COAL-FIRED STEAM GENERATORS

	STANDARD	UNCONTROLLED
SO_2:	1.2 LB/10^6 BTU	5 LB/10^6 BTU
TSP:	0.1 LB/10^6 BTU	6-10 LB/10^6 BTU
NO_2:	0.7 LB/10^6 BTU	1 LB/10^6 BTU

Figure 1. Clean Air Act--Driving Force for Flue Gas Cleaning.

Third, the Agency is considering the possibility of NSPS for industrial boilers which would be defined as being less than about 25 Mwe (equivalent) for nitrogen oxide, total suspended particulate and possibly sulfur oxides.

The President's recent energy message highlights the need for effective control technology on coal combustors. The message calls for the expansion of the annual coal production rate from the 700 million tons presently produced to over 1 billion tons by 1985. His policy also calls for massive conversion of existing utility and industrial power facilities from oil and gas to coal, and for essentially no new oil or gas industrial or utility boilers. Future options for these applications would generally be coal or nuclear, or one of the emerging energy technologies. Although the conservation aspects of the President's plan, and the assumption of strict environmental control trends to minimize environmental degradation, total emissions of nitrogen oxides and sulfur oxides, are projected to rise above present levels by 1985. The President's energy message also calls for accelerated research, development and demonstration for the so-called clean coal technologies: coal cleaning, flue gas desulfurization, particulate control, fluidized bed combustion, gasification, liquefaction and coal mining. In fact, we, in the EPA energy-environmental program, have been working with the Office of Management and Budget at planning an accelerated program for certain coal combustion control technologies. We are hoping to get a relatively large funding spike in fiscal year 1978 to accelerate our present development/demonstration efforts in the following technology areas: flue gas desulfurization, nitrogen oxide control, particulate control, coal cleaning, and coal processing.

So what we basically have is the possibility of more stringent emission regulations, in light of possible Clean Air Act revisions and upgrading of present NSPS, superimposed on an energy plan which calls for increased burning of coal. Clearly, effective and low-cost control technology for utility and industrial sources are needed in the near term.

Figure 2 summarizes the critical problems associated with utility and industrial conventional combustion. This table attempts to briefly describe: the primary problems associated with such combustion; whether or not there are existing standards; major near-term control technologies available; the present status of these technologies; the secondary residuals produced by these technologies; and finally the needed control technology R&D in order to resolve some of the remaining problems. As you can see, the primary problems associated with industrial conventional combustion include the primary air pollutants, nitrogen oxide, sulfur oxide, particulates and potentially hazardous materials, as well as some of the waste and water effluents associated with these control technology and the power plant itself.

Now that I have completed my background discussion, I'd like to present some of the highlights of our ongoing research, development and demonstration program.

Figure 2

DESCRIPTION OF PROBLEM	STANDARD PRESENTLY ESTABLISHED	TYPE OF FGC CONTROL TECHNOLOGY	PRESENT STATUS	SECONDARY RESIDUALS	NEEDED CONTROL TECHNOLOGY R&D (INCLUDING ASSESSMENTS)
PRIMARY POLLUTANTS SO_2	YES NSPS & AAQS	COAL CLEANING	1ST GENERATION DEMO PLANNED	HIGH-S REFUSE	A) ELIMINATION OF SECONDARY POLLUTANTS B) DEMONSTRATE PRACTICABILITY C) BROADEN APPLICABILITY
		FGD	1ST GENERATION IN FULL SCALE DEMO 2ND GENERATION IN BENCH AND/OR PILOT SCALE	SLUDGE, PURGE STREAMS	A) ELIMINATION OF SECONDARY POLLUTANTS B) IMPROVE RELIABILITY C) BROADEN APPLICABILITY D) IMPROVE ENERGY EFFICIENCY
NO_x	YES NSPS & AAQS	COMBUSTION MODIFICATION	COMMERCIAL FOR SOME NEW UNITS	POSSIBLY MORE PARTIC. AND CO	A) BROADEN SOURCE APPLICABILITY B) IMPROVE ENERGY EFFICIENCY C) IMPROVE NO_x CONTROL EFFICIENCY D) MINIMIZE IMPACT OF RESIDUAL POLLUTION
		FLUE GAS TREATMENT	PILOT SCALE AND DEMO IN JAPAN	VARIES WITH PROCESS	
PARTICULATES	YES NSPS & AAQS	ELECTROSTATIC PRECIPITATORS	COMMERCIAL	FLY ASH	A) IMPROVE COST EFFECTIVE FINE PARTICULATE CONTROL B) BROADEN APPLICABILITY C) DEVELOP NOVEL DEVICES WITH IMPROVED CAPABILITY
		BAG HOUSES	1ST GENERATION DEMO		
		WET SCRUBBERS	1ST GEN. COMMERCIAL 2ND GEN. FULL SCALE DEMO		
		NOVEL DEVICES	BENCH OR PILOT SCALE		
POTENTIALLY HAZARDOUS MATERIALS	NO	UNDEFINED	UNDEFINED	UNDEFINED	PROBLEM REQUIRES DEFINITION

Flue Gas Desulfurization

I would first like to discuss our flue gas desulfurization (FGD) program. One can characterize these systems as producing either throwaway (disposable) or saleable products. In the "throwaway" FGD area, one of our most important single projects is the Shawnee lime/limestone prototype program which we've conducted with the aim of improving lime and limestone scrubbing processes. As many of you know, such processes have been selected for many utility applications; approximately 40,000 Mwe or approximately 3 billion dollars worth of these systems are presently in operation or on order at this time.

The Shawnee program has been a cooperative effort of the EPA, the TVA and the Bechtel Corporation. Two 10 Mwe scrubbers have been operated since 1972, and a 0.1 Mwe pilot scrubber has been operated in support of the two larger facilities since about 1973. This program has demonstrated long-term reliable operation of both lime and limestone processes. The particularly troublesome mist eliminator plugging problem has been solved by using a combination of careful operating conditions as well as carefully selected mist eliminator washing configurations. During the course of our program, we discovered the potential of unsaturated operation in order to avoid gypsum scaling which had plagued earlier commercial systems. Basically, this approach involves selecting operating parameters so that scrubbing liquors never get saturated or super-saturated in calcium sulfate thereby avoiding potential scaling problems. Also, during the course of the program, we've learned how to achieve high-alkali utilization. For example, limestone utilizations of over 90% have been achieved. This leads to lower alkali requirements and lower sludge production rates, both of which yield lower operating costs. We have also achieved high sulfur oxide removal efficiencies. Typically, efficiencies for both lime and limestone systems in excess of 95% can be achieved without an excessive economic penalty. One of our most recent findings is that minor process modification can allow for sludge oxidation by gypsum producing a material capable of 90% dewatering by filtration. Since last year, we've developed a design/cost computer model which acts as a data base for all the information the EPA, TVA, Bechtel team knows about lime/limestone scrubbing and allows a given utility or other FGD user to input application parameters and output a conceptual design along with some pretty good cost estimates.

We have been working with the Air Force in operating and testing a lime scrubber system on a 21 Mwe coal-fired industrial boiler at the Rickenbacker Air Force Base. This unit started up in March 1976, and, although there were some boiler control and fan problems, the efficiency and reliability of the scrubber have been good. Also, it appears that the economics of such scrubbing systems on industrial boilers of this size do not appear prohibitive.

As an alternative to lime and limestone nonregenerable FGD systems, our program has been actively developing the double alkali scrubbing process. Although the double alkali system has basically the same chemicals entering the process and leaving the process, they do have several potential advantages over lime/limestone scrubbing processes. These include: less energy consumption; higher sulfur oxide removal efficiency; lower maintenance; and, lower capital and operating costs.

The EPA program has actively developed double alkali technology at the bench and pilot levels. We've worked with Southern Services at 20 Mwe electric prototype system and, most recently, we've worked with the General Motors Company at applying a double alkali process variation to one of GM's industrial boilers. In the past, this double alkali scrubber had generally good operability on the 32 Mwe industrial boiler, although some problems were encountered. It should be noted that, as for the previously mentioned Rickenbacker lime unit, the approximate capital costs, on this size industrial boiler, of $100/Kwe do not appear excessive.

Recently, the EPA announced its plans to demonstrate the double alkali process on a high-sulfur coal utility boiler. The Louisville Gas and Electric Company and its 270 Mwe electric Cane Run No. 6 unit was selected for this demonstration. Combustion Equipment Associates/Arthur D. Little comprise the process supplier team. I think it is noteworthy that the cost of this unit, and these costs are fairly firm, are estimated to be only $55 per Kwe capital costs; and 2.5-2.9 mills/Kwe hour for total annual revenue requirements. Also, only 1.1% of the power plant's energy output is required to run the fans and pumps for this process. This is roughly one-third to one-half the energy requirement of similar lime or limestone systems.

As an alternative to lime and limestone systems and their inherent sludge production, we have been active at developing and demonstrating regenerable (or saleable) product FGD systems. For example, we have demonstrated the promising magnesium oxide scrubbing process at Boston Edison's Mystic Station. This scrubbing facility was tested on a 155 Mwe oil-fired boiler and produced saleable sulfuric acid. The test program was initiated in April 1972 and completed in June 1974. Although many early problems were identified, particularly those associated with the various solid handling operations, operability improved substantially toward the end of the test program. Unfortunately, no meaningful demonstration of this process has been performed on the critical coal-fired combustion units.

Our major ongoing project in the regenerable area is the Wellman Lord demonstration test program. Wellman Lord technology involves scrubbing with a soluble reactant followed by thermal regeneration producing concentrated sulfur dioxide which can yield either sulfuric acid or elemental sulfur. This process has been successfully demonstrated in Japan on a variety of oil-fired facilities. The EPA demonstration program is on a 115 Mwe electric coal-fired facility at the Northern Indiana Public Service Company and produces elemental sulfur. This facility started up in April 1976 but due to a boiler explosion we are now in a restart-up mode. Hopefully, definitive findings on this process will be available at our next conference.

Recently, the Atomic International's Aqueous Carbonate Process has been selected for demonstration. The process will be demonstrated at Niagara Mohawk's Huntley Station and we are hoping that the system will start up in early 1979. It offers cost and other advantages over alternative regenerable processes, but must be considered a relatively high-risk venture due to the relatively small scale of previous test experience. Also note that the EPA is working with the U.S. Bureau of Mines in applying the regenerable Citrate Process to a large industrial facility. Figure 3 summarizes the major EPA-sponsored demonstration programs for both throwaway and saleable project FGD processes.

In addition to our demonstration activities, TVA working for the EPA has conducted a series of very relevant by-product marketability studies which help put the sulfur, sulfuric acid, and other sulfur by-product sale situation in perspective. Also, studies have been performed at evaluating alternatives to scarce natural gas, as the reductant materials to produce elemental sulfur from the concentrated sulfur dioxide associated with many regenerable FGD processes.

Let me conclude my discussion of our FGD program by briefly mentioning three other important programs. First, the TVA has prepared a number of FGD process economic studies which in my mind are the most reliable cost estimates for both throwaway and saleable FGD processes. Secondly, the EPA working with the Council on Environmental Quality is working on a scrubber availability study which attempts to compare scrubber availability to that of other power plant components. Preliminarily, it appears that there is insufficient information to do a statistically convincing comparative study. However, it has become apparent that several major power plant components appear to have reliabilities lower than some of the more recent FGD systems.

Finally, I'd like to mention the very active technology transfer program in the FGD area. Some of the outputs of this program include the PEDCo Status Report (published every other month) which summarizes what's going on in the scrubber field both in terms of operating and planned systems. Also, we now publish quarterly RD&D status reports which summarize the results of our ongoing research program. We are preparing lime and limestone data books and cost and reliability handbooks which present potential users with important information on commercial and noncommercial technologies.

Nitrogen Oxide Control

Now, let us discuss our NO_x control program. I think a little background might be in order so I've added some background information that I think is relevant. As many of you know, there was an unreliability problem discovered in the ambient air quality measurement technique for NO_2 back in 1972. Prior to discovery of the problem, it was believed that 47 Air Quality Control Regions (AQCR) out of the total of 247 AQCRs for the country had an NO_2 ambient air problem. What we've found out is that due to an inherent measurement error, ambient levels of NO_2 were measured too high. Using more accurate techniques, only four areas (AQCRs) for the country really seemed to have an NO_2 problem.

However, since 1972 there hasn't been too much progress in NO_2 control from either stationary or mobile sources. As a result, they are now finding new AQCRs exceeding the NO_2 standard and, quite frankly, the trend seems to be for further NO_2 ambient quality problems. Therefore, our present NO_2 control strategy does not appear very effective. Our present control strategy, basically, includes control of both mobile (automobile) sources as well as stationary sources.

Figure 3

EPA-SPONSORED STACK GAS DESULFURIZATION DEMONSTRATION SYSTEMS

EPA-SPONSORED PROCESS (BY PRODUCT)	PARTICIPATING UTILITY	PROCESS DEVELOPER	LOCATION	UNIT SIZE AND TYPE	EXPECTED START UP
NON-REGENERABLE					
LIMESTONE SLURRY SCRUBBING (SLUDGE)	TVA	BECHTEL AND OTHERS	SHAWNEE UNIT 10 PADUCAH, KY	10 MW COAL	UNDER WAY
LIME SLURRY SCRUBBING (SLUDGE)	TVA	CHEMICO, BECHTEL, AND OTHERS	SHAWNEE UNIT 10 PADUCAH, KY	10 MW COAL	UNDER WAY
DOUBLE ALKALI SCRUBBING	LOUISVILLE G&E	CEA/ADL	CANE RUN 6	270 MW	EARLY - 1979
REGENERABLE					
MAGNESIA SLURRY SCRUBBING - REGENERATION (98% SULFURIC ACID)	BOSTON EDISON	CHEMICO-BASIC	MYSTIC STATION 6 BOSTON, MASS	150 MW OIL	COMPLETED
SODIUM SCRUBBING REGENERATION (SULFUR)	NORTHERN INDIANA PUBLIC SERVICE CO	DAVY POWERGAS ALLIED CHEMICAL	D.H. MITCHELL STATION 11 GARY, IND	115 MW COAL	LATE - 1975
AQUEDOUS CARBONATE	NIAGRA MOHAWK	ATOMICS INTERNATIONAL	HUNTLEY STATION	100 M COAL	EARLY - 1979

I should point out that almost one-half of the NO_x emissions are from mobile sources; a little more than one-half are associated with stationary sources. So both are of interest if we are to achieve NO_x air quality goals.

We have set so-called interim standards for automobiles. They are not very stringent standards, and are in fact substantially less stringent than the Clean Air Act goal. Due to economic, technological and political considerations, it appears that in the near term relatively moderate NO_x emission standards will prevail for autos.

Also, the new source performance standards philosophy is based on best available control technology. Since control technology for stringent control is not available, the NSPS for utility boilers is not very restrictive and only requires, as I indicated earlier, on the order of 30 or 35 percent control. There's also an NSPS for nitric acid plants which is a significant contributor to the NO_x problem.

So, our present strategy doesn't seem to be sufficient to get these AQCRs back into line, and for that matter to turn around the trend toward additional AQCRs getting out of standard. Therefore, additional control of stationary sources beyond the present level may be necessary. Of course, the NO_x problem is more complex than just NO_2; NO_x is a major precursor for photochemical oxidant and nitrate production.

There are three major categories of control for NO_x control for stationary sources. The only near-term technology is combustion modification, which the present EPA program is emphasizing. This technology is the basis for the present new source performance standard on large fossil fuel generators. Flue gas cleaning is the second technology. It's similar to flue gas desulfurization, and probably should be called flue gas de-nitrification. We have several embryonic programs in that area which I will briefly describe.

This combustion modification program aims at developing technology capable of controlling emissions from the two major sources of NO_x from stationary sources; namely, "thermal" NO_x and "fuel" NO_x. One hopes to control "thermal" NO_x by lowering the combustion temperature since the equilibria relationships are such that lower temperatures retard NO_x formulation, i.e., higher temperatures favor the oxidation of nitrogen. And, one can control "fuel" NO_x problems by lowering oxygen concentration. One might note that the control approaches are generally common to both thermal and fuel NO_x, with the exception of flue gas recirculation, which is really oriented primarily toward minimizing thermal NO_x.

One has to be careful implementing these techniques since it is possible to aggravate other pollutant emission problems. We could, for example, increase emissions of carbon monoxide or particulate matter, if we drastically lower excess air. We could also lower thermal efficiency with approaches such as flue gas recirculation. These techniques can also lead to operating problems since boilers will not be operated in some cases under the design conditions that they are designed for. However, the results of our program to date indicate that each of these potential problems are controllable if one is careful about the particular control technology and the design parameters utilized.

Let me now discuss the ongoing nitrogen oxide combustion modification program. I'll discuss this program by source area: utility and large industrial boilers; small industrial, commercial and residual systems; stationary engines; and industrial processes and after-burner equipment.

In the utility and large industrial boiler area, the program's major effort has focused on staged combustion approaches. By utilization of this combustion modification technology which involves adding combustion air sequentially in more than one location to minimize total oxygen requirements and combustion temperature, control levels of 0.45 lb/10^6 Btu appear achievable. We are presently planning corrosion tests to ascertain whether or not boiler tube corrosion is an inherent problem. It has been postulated by some that the reducing environment associated with staged combustion can remove the protective oxidative coatings from the tubes, thereby accelerating corrosion. Therefore, corrosion tests are considered quite important.

Perhaps our most encouraging activity in the NO_x program is our work in the low-NO_x burner area. By redesigning pulverized coal burners to more carefully combust coal, experimental results have indicated that NO_x levels of 0.2 to 0.3 lb/10^6 Btu are achievable. This represents overall control of an uncontrolled coal-fired boiler of over 70%. Since such burner technology appears inherently inexpensive, this could be the answer to low-cost nitrogen oxide control from both industrial and utility pulverized coal boilers. If we receive the incremental fiscal year 1978 funding that I mentioned earlier, we will be able to proceed on an orderly demonstration program aimed at evaluating this approach at sizes culminating in an integrated full-scale demonstration program.

In the small industrial, commercial and residual system area our program's emphasis has focused on residual oil package boilers, residential furnaces and coal-stoker boilers. We have demonstrated that staged combustion is an effective control approach on oil-package boilers. Preliminary information indicates that optimum burners can achieve 70% NO_x control over conventional burners for residential distillate oil furnaces. Our work in the coal stoker areas has been limited so far to the development of emission factors for existing designs. A combustion modification technology program is presently under development for this increasingly important class of coal boilers.

Staionary internal combustion engines are a major source of nitrogen oxide emissions, primarily because of their widespread use as the prime mover for pipelines and gaslines around the country. Preliminary work indicates that it may be possible to lower nitrogen oxide concentrations in combustion gases to 50-100 ppm. This would represent an overall NO_x control of 75%, and a substantial improvement both in NO_x efficiency and overall energy conversion efficiency to the presently available control technology, which involves introduction of water into the combustion zone.

In the industrial processes and after-burner equipment area, we have a relatively low level of activity due primarily to limitations in funds. Our near-term goal in this area is to characterize NO_x and other emissions for these facilities.

Let me briefly describe the NO_x flue gas treatment research and development program. One might ask, in light of the comprehensive combustion modification program I have just described, "Who needs flue gas treatment?" and "What is the advantage of this technology over combustion modification?" Well, the only identifiable advantage in my mind is that this approach has the potential for very high NO_x removal efficiencies which could conceivably be required if standards were to tighten in the years ahead.

However, you pay the price for high removal efficiency in terms of high capital and operating costs and system complexity relative to combustion modification technology. These approaches are under active development in Japan due to the stringent ambient and emission standards for nitrogen oxides there. Two basic approaches are being developed, dry and wet processes. The dry processes are the simpler of the two and generally involve a chemical reduction reaction. Typically, ammonia is used as the reductant and a selective catalyst is needed to reduce nitrogen oxide to elemental nitrogen and oxygen. Problems with this approach include uncertainty regarding the viability of this process for coal-flue gas, the possibility of secondary emissions (such as ammonium sulfate), and potentially high costs associated with capital expenses and reagent needs. Wet processes are generally more complex and can involve oxidation to nitrogen dioxide followed by a scrubbing step; others reduce the nitrogen oxides in solution. For the oxidative/reductive approach, ozone is a typical oxidant. The main advantage of this class of processes is the potential for combined sulfur oxide and nitrogen oxide removal. Problems include large ozone and energy needs for the oxidative/reductive process and the production of secondary wastes and high costs for all versions of the wet processes. The EPA program in this area involves piloting promising processes treating flue gas from coal-combustors, borrowing heavily from Japanese technology on oil-fired boilers there. Two pilot programs are in the final contractor selection phase, one will involve nitrogen oxide removal only and the other will investigate concurrent removal of nitrogen oxide and sulfur oxide.

Fine Particulate Control

First a little information in the way of background. Fine particulates are health hazards because they are airborne for extended time periods, can penetrate deeply into the lung, and can act as transport agents for other pollutants. Our research, development and demonstration program includes the following major areas:

- Improvement of characterization of present technology, e.g., electrostatic precipitators, scrubbers, fabric filters
- New ideas/novel devices
- High temperature/high pressure control technology
- Collectability of dust
- Control from low sulfur coal combustors

Our program is actively evaluating the potential for electrostatic precipitators as high efficiency fine particulate control devices. We have characterized precipitators for seven particulate sources, and developed a math model which characterizes precipitator performance as a function of particulate characteristics. We have concluded that precipitators offer the possibility of high fine particulate control when there is no ash resistivity problem. Precipitators are very sensitive to the chemistry of the ash they must collect. For example, for low sulfur coal combustion facilities, the ash generally is of a low resistivity since there is not sufficient sulfur trioxide to raise the ash conductivity thereby leading to collectability problems. Our program is actively considering ways of upgrading precipitator performance when the ash has a less-than-optimum resistivity. We are actively evaluating fly ash conditioning agents such as sulfur trioxide, ammonia, etc. We are also actively evaluating the possibility of precharging the flue gas upstream of the precipitator in order to improve the collectability of the ash. We are presently planning a pilot demonstration of an attractive precharging approach. We are carefully coordinating our program with the Electric Power Research Institute who is also active in this area.

We are also evaluating and developing various scrubber devices for the removal of fine particulates from combustion facilities. We have evaluated ten devices on a variety of particulate sources, and currently find a consistent pattern where fine particulate removal efficiency is highly dependent on pressure drop (and, therefore, energy requirements) of the scrubber device. Generally, the higher the pressure drop the better the fine particulate removal efficiency. However, at least one scrubber type has appeared uncharacteristically efficient in fine particulate removal, namely, the turbulent contact absorber (TCA). Our studies have indicated that a condensation mechanism is responsible for this good performance. We are evaluating this mechanism more carefully and hope to be able to apply it to other scrubbers in other facilities. We are also piloting a flux force/condensation scrubber which uses a condensation mechanism for efficient fine particulate removal. Recent data indicate that scrubbers may be limited in their fine particulate performance by mist eliminators. Mist eliminators are designed to avoid the entrainment and carryover of scrubbing liquors from the scrubber into the existing flue gas. It appears that inefficient mist eliminators on commercial units have allowed such entrainment thereby leading to carryover of particulates with subsequent degradation of fine particulate removal performance. Studies continue in this area.

Fabric filtration is being evaluated as a fine particulate control scheme. We have tested filters applied commercially to three sources, and find that fabric filtration is quite efficient down to 0.3 microns. These devices have energy requirements between the low energy usage precipitators and the high energy usage scrubbers. Our present program is aimed at increasing the applicability, operability and economic desirability of these very promising devices. We are presently planning to be involved in a 350-megawatt demonstration program applying fabric filtration to a low-sulfur coal utility boiler. This will be the first commercial operation of a low-sulfur coal fabric filtration combination. Our program has also been active at evaluating new ideas and novel devices for the removal of fine particulates from various sources. Many of these devices have been tested at bench scale and the most attractive devices are scheduled for pilot scale testing pending availability of funds.

We have also actively pursued mobile particulate control devices that enable us to collect data from a variety of particulate sources. We presently have constructed and tested mobile units of electrostatic precipitators, scrubbers, and fabric filters which can allow us to determine what the best control device might be for a given application and its associate dust problem.

A final element of our program is the control of particulates from low-sulfur coal combustors. This is really not a new or separate part of our program, but actually incorporates our ongoing work in other areas. However, we find it helpful to focus in on this major problem afflicting those utility and industrial sources who must meet particulate standards and burn low sulfur coal. Our present emphasis at this time is the development of fabric filtration and modified electrostatic precipitators for cost-effective particulate control from these sources.

In conclusion, I believe the results of the conventional fossil fuel control technology program I have discussed this evening will go a long way in helping our nation achieve two of its most important goals compatibly: energy availability and environmental protection.

SESSION II - PRECOMBUSTION PROCESSES

SESSION CHAIRMAN: P. STANLEY JACOBSEN, COLORADO SCHOOL OF MINES
RESEARCH INSTITUTE

The Air Quality Act of 1963 initiated at all levels of government an effort to preserve the nation's air quality. Because of the large role that coal shares in providing the total fuel energy consumption of the nation, the effects of coal combustion in electric power generation were given special emphasis. Coal consumption by utilities was 404 million tons for 1975 and may be as high as 700 million tons by 1985, and as recommended by the President could be over 1200 million tons in the year 2000.

Control of sulfur oxide emissions from fossil-fuel-fired combustors has for years been considered desirable, but with the promulgation of air quality standards the control has become mandatory. Typically, the removal of sulfur has been accomplished by postcombustion processes such as flue gas desulfurization. But the advantage of utilizing precombustion processes as well offers very definite advantages, such as:

1. Using high sulfur coals with little to medium physical cleaning.
2. Availability of a more uniform coal.
3. Lower effective fuel transportation costs.
4. Reduced maintenance costs.
5. Lower coal pulverizing and ash disposal costs.

The overall advantage of combining precombustion processing with postcombustion processing can be substantial up to a savings of 140% over using postcombustion processing alone.

To bring into perspective the complete gamut of precombustion processes, the session commences with papers covering the following four areas: an overview of coal preparation; the influence of mining practices on the quality of raw coal; research aspects of coal preparation; and transportation of coal. Three papers in the evening session cover rather innovative approaches to coal preparation, namely: chemical coal cleaning, magnetic desulfurization, and a waterless coal cleaning method, called The Otisca Process.

The entire combustion process including precombustion, combustion, and postcombustion surely must be considered as an integrated whole. It is anticipated that the papers on precombustion processes will serve to refocus attention on the important role this sometimes-neglected segment plays in the overall combustion process.

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COAL PREPARATION
HISTORY AND DIRECTION

by

Robert L. Llewellyn
Vice President
Roberts & Schaefer Company

Historically, coal has been prepared in some fashion since the beginning of mining over 150 years ago in the continent alone, and double that figure in Europe. Slotted hand shovels were used to leave the untreated fines inside the mine; men, boys and even women sorted the coal from impurities on picking tables. Then, many ingenious men, too numerous to mention, invented jigs, tables, launders and vessels; using water and air, and the combination of both to separate the coal and refuse.

Later, sand, minerals (such as magnetite) and heavy liquids were added to these various washers to increase their efficiencies of separation. Fifty-five years ago oil agglomeration was patented here in the States to clean ultra fines, but the use was considered uneconomical because these fines (at the time) could be wasted. Then, over 30 years ago electrostatic coal cleaning was demonstrated in a test plant on 14m x 0, and this system is still resurrected by some about every 10 years without success.

Some confused Convertol with agglomeration, which was a process using oil with the fines to dewater and improve the bulk density. Agglomeration reduces the ash. Electrostatic was a unique idea to dry clean fines by surface separation; it worked in the laboratory, but not in practice because the coal had to be practically bone dry and drying coated the particles.

We in the coal preparation field are very fortunate to have excellent cleaning devices available for obtaining efficient physical separation of the raw feed from the mines throughout our nation. Chemical processes are also being considered to make coal practically ash- and sulphur-free and the activity of all this science is very exciting to every man and woman connected with coal, which will be affecting the energy field for the next decade. Huge sums of money will be expended by government and industry and it must be spent wisely; it must not be wasted.

If electric power is to be most economical, the fuel must be obtainable at a reasonable cost. All of us have been made aware of this when receiving our monthly or quarterly bills, showing the fuel cost adjustment. Therefore, it behooves all of us to investigate the lowest cost mining and cleaning systems. We have "mine mouth" operations, which were

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recognized during the past 15 years as an excellent method to provide cheap fuel by locating the power plants at the coal mines. Pipelines from Cadiz to Cleveland transported coal in slurry form from the mine to the power station, which was a pioneer to other pipelines in the west for the same purpose. Railroads obtained unit train load rates to greatly stimulate coal transportation from mines to power plants by rail. Mining equipment for surface and deep mines have been manufactured to improve the cost of coal to the ultimate user.

Never before have there been so many people involved with the art of coal preparation. This will continue into the next century. And with such people whose backgrounds vary in education and talent, the possibility for developing new cleaning techniques are bound to be fantastic. The interest in coal preparation has attracted numerous companies whose expertise were in different fields of engineering and construction.

Many consultants have recognized the tremendous growth in the immediate future in coal preparation and now there are industries outside of coal mining who are engaged in a tremendous effort and with financial aid in the coal preparation field. Utility companies with their vast networks in the U.S.A. have sought and secured large coal reserves for energy resources. Oil companies are making huge investments in coal properties, which will be mined and the product beneficiated to suit the use in the making of energy or steel. Those people involved have learned that many railroads and steel corporations are already owners of coal lands since the turn of the century.

It is predicted that great activity will be observed as we look toward the year 2000. As coal production doubles, or triples, the type of coal will have to be prepared by the highest efficiency equipment available. These coals left unmined in the east and midwest by our grandfathers or great-grandfathers will require the best cleaning methods to obtain the ash, sulphur and Btu requirements. Our ancestors had to mine the cleanest seams in the area, because coal preparation was in its infancy and the price of coal was relatively cheap.

For your information, the first million dollar coal preparation plant was built near Benton, Illinois, for U.S. Steel in 1918; the book, Coal Washing by Prochaska, described the plant to some extent. I visited the plant in 1938 and personally saw the Plato Concentrating Tables and Feldspar Jigs for fines which were intended to reduce the sulphur content for metallurgical purposes.

Coal cleaning systems can be utilized economically, but only if applied properly. Coal Washers differ significantly; magnetic recovery circuits have wide variations, and unless these factors are not diligently scrutinized, preparation plants will be built without the best coal beneficiation equipment or systems.

Anyone who has studied flowsheets for years can readily observe the various systems to prepare coal. First, I believe that one should thoroughly acquaint themselves with what is going on underground. That is where the coal and refuse are formed. Just lately I have learned how much bottom and roof gets into the R.O.M. The plastic bottles used for water inside has become a problem. We all have known about wood, metal, aluminum cans, and now plastic bottles have to be removed before any cleaning system.

Preparing the coal ahead of cleaning is most important; recognize that breaking and/or crushing can help or hurt the raw product. Often times reducing the size improves the quality and recovery on some coals.

Necessity breeds invention which brought on devices to prepare coal in the past and some of us here will perhaps be involved in some way in the future. However, there is nothing wrong to apply proven equipment. We do not have to invent the Edison light bulb again; the "bulb" has been improved in our lifetime by many companies.

We must learn by personal experiences and from experiences of others. It is very difficult to "weed" out good and bad information. Some integrity has been lost in our life style and I believe that presently you cannot believe everything you read or hear as you could some years ago.

Conferences like this one attract people who are very eager to learn, otherwise they would not be attending. The program input should be rewarding to all who are interested in coal and its growth.

THE INFLUENCES OF MINING PRACTICES ON COAL PREPARATION

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There is no doubt that the coal reserves in the United States are more than adequate to meet the energy needs of the country. The reserve base in the East is over 200 billion tons. Of that total, it is estimated that 160 billion tons will have to be extracted by underground mining methods owing to the depth of cover, which averages over 600 feet in the seams that are currently being exploited. The maximum cover in the East in active mines is about 2,300 feet. Extraction by surface methods seldom exceeds 100 feet in total depth, but this is more a function of seam thickness and quality than of equipment capability. Recoverability averages from 50 to 60 percent for underground and from 80 to 90 percent for surface methods. Again, coal quality and environmental aspects tend to constrain the systems.

Coal mining is a high-volume, high-production effort; it is highly developed art. Preparation of the product has its inception in exploratory stages prior to earthmoving. The area to be mined is drilled on 5 mile centers or more, and based on an analysis of the cores, a decision is made whether or not to proceed. Favorable analyses lead to a second-phase program whereby the drilling centers are tightened to anywhere from 1 to 3 miles, and again a decision point is reached before finally going to 1/2" to 1/4-mile core hole centers. Intelligence gathered on the deposit characteristics includes superjacent strata information as well as coal character. Selection of mining and preparation equipment, layout of the mine, location of points of entry, areas to be mined and mining sequence, drainage of the workings, method of mining, and other mining and marketing considerations are based largely on the analysis of the cores and any outcrops. High-resolution seismic reflection may also be used to give definition to the deposit in terms of geologic anomalies (faults, channel sands, washouts, etc.) that may influence extraction.

Information gathering relative to deposit characteristics continues throughout the life of the mine. Isopach maps are prepared showing the deposit properties of interest, be they sulfur, volatile matter, BTU, or ash. These are useful in establishing blends of coal from various sections of the mine to produce a more marketable product. Proper input in the early stages of mine planning is of incalculable importance when considering the life of the property, which may be in excess of 25 years, and the total planning effort which may take 5 years before production is realized. Once a commitment to layout, equipment, and method has been made, any changes could be economically disastrous.

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The decision whether to surface mine or to attack the deposit by underground methods is based on the extent, quality, and thickness of the deposit and topography. Basically, a ratio of 20 feet of overburden per foot of coal is the maximum stripping that is currently undertaken. The size of the equipment is also based on the stripping ratio, the concern being to match coal extraction rates and overburden removal rates over the life of the property. Fragmentation by blasting or by ripping equipment and loading practices affect the size and quality of the coal extracted. Proper choice of equipment for removing overburden, for cleaning the top of the exposed coal bench, and for loading the coal can enhance the marketability and/or the beneficiation character of the product.

Augering mining is a technique that can be used to extend production capability after surface mining methods are no longer economical. It is less efficient in terms of recovery. Usually, the augers are sized 6 inches or more under the seam thickness to be taken in order to leave coal on the top and/or on the bottom, thus minimizing rock contamination. Research is continuing in the development of coal-rock interface detectors which allow for vertical control of the auger to maintain its position in the seam. Auger coal is normally coarse and dry, but product size decreases with depth of penetration. Webs of coal are left between holes to insure the integrity of support during mining. Too thin a web may lead to seizure of the unit, as floor and roof converge under stress. Attempts to develop low-cost reliable sensing equipment to maintain consistent and substantial web thicknesses are being made.

Selective mining can be readily accomplished underground by producing coal from various sectionsof the mine and blending the product by controlling section output. Of the two generally used methods of mining, room-and-pillar mining is more amenable to selectivity than longwall mining. Flexibility of the former in terms of the number of operating units and relative ease of moving production units from one area of a mine to another leads itself to planned development and scheduling. Room-and-pillar development can be accomplished by either conventional methods (cutting, drilling, blasting, loading, and hauling) or continuous methods where a single machine mechanically rips the coal from the face, thus eliminating drilling and blasting. Studies have been conducted on both these systems in terms of quality and quantity of product, and they show significant differences.

While size of product is a function of the seam characteristics and is governed by the hardness of the coal and fracture system, continuous mining units generally produce finer sizes and introduce more extraneous materials into the product than do conventional units. The difference is due more to operator judgment than to anything else. Lower rotational cutting speed and deeper bit penetration could reduce the size differential between the two systems. The increased use of continuous miners at the expense of conventional units attests to the fact that productivity is the thrust of today's mining. The burden is on the cleaning plants to upgrade the product.

Relief to overtaxed cleaning facilities can be accomplished by exercising face preparation techniques, and its importance should not be overlooked or minimized. Ash-forming or sulfur-bearing impurities can be avoided in the mining process if they occur, as is often the case, in association with the bottom and top portions of the seam. The coal itself is often a better room or floor material than the associated shales and clays, and in some instances a 6-inch layer left in place provides a better bearing surface or can give better protection against falls of roof as well as yielding a better product. Vertical distribution of impurities as well as seam thickness dictates the acceptability of this practice. Cutting and blasting in conventional mining can be used to advantage to control banded impurities. Soft bands can actually be cut out, or hard bands can be fragmented for size control and eventual ease of physical elimination in a screening operation.

Longwall mining is touted as a safer, higher production system than room-and-pillar. There are approximately 80 active units in the United States today, and they account for about 5 percent of the country's underground production; in foreign countries, longwall mining is almost universally used. There are opportunities in this system for both high production and quality control. The miner at the working face is in a protective envelope of hydraulic supports (chocks or shields) and is in better control of the environment. Dust and methane are more easily diluted by directed quantities of air. Additionally, the size of the panels, i.e. up to 600 feet wide and a mile long, allows for more continuous operation. The mining unit (shearer or plow) is generally under better control in terms of its attitude in the coalbed. More importantly, especially in the case of the shearing machine, there is an opportunity for guidance control and remote operation with the potential for better quality control and higher production. The mining machine can be kept within the confines of the seam, and a mining strategy to leave room and/or floor coal can be readily established. Probes, sensors, and controls leading to full face control are being developed, and some are already available. The economic practicability of the control systems has yet to be established.

The preceding discussion is by no means all inclusive and is fraught with generalities. The intent here is only to give the nonminer a glimpse of the mining processes. The high degree of variability of coal seams and associated strata must be recognized. It is this fact that makes each mine unique and product control difficult.

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CURRENT COAL PREPARATION RESEARCH AND DEVELOPMENT

by

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The renewed interest in coal preparation and its rising importance are evidenced by the many new and innovative research projects ongoing around the country. The purpose of this paper is to point out and describe some of this research. Some of the Bureau of Mines new projects and updates of the major ones will be covered, followed by a few others from industry and other Government agencies.

The Bureau of Mines has recently awarded three research contracts to study chemical coal desulfurization, dewatering, and high-gradient magnetic separation (HGMS). Under one contract Jet Propulsion Laboratory will perform bench-scale desulfurization experiments with the aim of optimizing their low-temperature chlorinolysis process. This process looks promising as an organic sulfur removal step following physical removal of pyrite, because it reduces both pyritic and organic sulfur (up to 80 and 50 percent, respectively). At present, there are several other chemical desulfurization processes being researched with only one or two ready for demonstration units.

The dewatering contract is with Dravo Lime Co. and is titled "Management of Coal Preparation Fine Wastes Without Disposal Ponds." Fine wastes will be sampled at 10 selected preparation plants and analyzed for their physical, chemical, and engineering properties. Bench-scale stabilization tests will be conducted using Calcilox and other stabilizing agents. The results will be evaluated for effectiveness in hardening fine refuse.

The third contract was awarded to the Naval Ordnance Station at Indian Head, Maryland. They will investigate the feasibility of magnetically separating pyrite from finely crushed coal dispersed in fuel oil. A Frantz Ferro Filter containing a stack of closely spaced grids will be used for the experiments. The Bureau is also in the process of establishing in-house capability in high-gradient magnetic separation (HGMS). A high-gradient magnetic separator has been purchased from Sala Magnetics to treat finely ground coal. The results will be compared with representative fractions treated by the Bureau's two-stage coal-pyrite flotation process.

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A continuing HGMS contract proposes an application different from removing pyrite. Researchers at MIT are studying the problem of recovering fine magnetite from dense-medium circuits. Recent advances in the cleaning of finer sizes of coal require that the entire coal-magnetite streams be fed directly to magnetic separators. Because of their high capacity, fewer HGMS units may be needed to handle a given flowrate than conventional drum-type separators, and at a higher recovery of fine magnetite particles.

The Bureau's lignite development and utilization program is composed of several projects. In-house work is being done on the washability of Texas and Western lignites to assess ash and sulfur reduction potentials. Also, work on an ion exchange process for sodium reduction is in progress. In conjunction with this work, the Salt Lake City Metallurgy Research Center, through an interagency agreement, is developing scale-up data for the design of a continuous ion exchange pilot test facility. Finally, a contract for the development and demonstration of a lignite-pelletizing and pellet-drying process was awarded to Holley, Kenney, Schott, Inc. The initial research and development phase of the contract will be carried out at Michigan Technological University to determine such things as optimum size consist of the lignite, type of binder, and pellet size.

Two of the Bureau's fine-coal-cleaning projects are entering into new phases, the dense-medium cyclone and the two-stage coal-pyrite flotation. A closed-loop dense-medium cyclone test circuit has been installed with the objective of detailing and optimizing the performance of cyclones for fine-coal cleaning at lower-than-normal specific gravities of separation. The program is in cooperation with the owners of the Homer City Coal Preparation Plant, the Environmental Protection Agency, and the Electric Power Research Institute.

A coal-pyrite flotation demonstration unit has been constructed at Barnes and Tucker Lancashire No. 25 mine. It will process 12 tons per hour in a pyrite flotation circuit to show the improvement in sulfur reduction over conventional flotation. Also, an instrumentation circuit which will control reagent addition according to the mass flow of the feed pulp will be added at Barnes and Tucker, after testing at the Bureau.

The Ames Laboratory--ERDA, located at the Iowa State University, is doing work on the magnetic fraction of coal fly ash. The work covers three areas: (1) the recovery of the magnetic iron oxide from the fly ash by magnetic separation, (2) the evaluation of the physical and chemical properties of the two products of separation, and (3) the utilization of the magnetic material. Coal fly ash is a product of combustion and is being produced in increasing quantities as the use of coal increases. It represents a considerable source of iron and aluminum oxide.

Roberts and Schaeffer Co. has been experimenting with the upside-down, or inverted, cyclone. They recently started up the first commercial installation that uses dense-medium inverted cyclones. It is a 100-tph plant owned by the Wise Coal Co. in Virginia, and it is cleaning the full 1-1/2-inch by 0 size fraction in the cyclones. Early reports indicate good performance, although the plant operation is still being optimized.

A major piece of washing equipment which has remained essentially unchanged for many years is the Baum jig. Now, however, McNally-Pittsburg is developing an innovation which should reduce the amount of misplaced float material in the refuse. The float mechanism for sensing the bed depth and the refuse gate for rejection usually work the width of the jig, but McNally is dividing these units into three separately working sections across the jig. This accounts for variations in the bed. They have been running tests at some preparation plants with the revamped jigs, and results seem promising.

Finally, FMC Corp. is researching two pieces of cleaning equipment. One, the dry table, has been in development for a few years. It is a vibrating, wedge-shaped separator which is being touted for cleaning coal in the West where water is scarce. FMC is currently testing a 12-foot pilot unit on bituminous and subbituminous coals for ash and pyrite reduction and claim the cleaning performance is somewhat like that of a Baum jig.

The other FMC washer is a wet vibrating table, about the size and shape of the conventional concentrating table. Work on it has not been as extensive as on the dry table, but FMC is beginning additional research on it. The company claims it has over twice the capacity of a concentrating table, which would greatly increase the efficacy of wet tables in preparation plants.

These examples of current R & D projects show the wide variety of ideas in washing, dewatering, and desulfurization for Btu recovery and environmental protection. Many of these ideas have become feasible because of the high price of coal and the need to meet environmental regulations.

COAL TRANSPORTATION IN 1985

by

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Introduction

There are a number of basic questions concerning the transportation of coal. Some of these questions include: What are the factors affecting the modes by which coal will be shipped? Can we supply the required facilities and equipment? And, will special incentives or legislation be required to insure that the demand for transportation services will be met? A great deal of analysis, and a fairly large literature, is part of the public record on this topic. By presenting and comparing some of these analyses, we can get a good handle on the magnitude of the transportation services which will be required.

It is the stated intention of the current Administration, as it was the goal of the previous Administration, that production and consumption of coal in this country in 1985 should be slightly in excess of one billion tons; the exact quantity is given in various places as anywhere from 1.1 billion tons to a "doubling" of our use based on 1975 or 1976 consumption. This same range of estimated use has been suggested by private sector sources, both within and outside of the coal and transportation industries.

Factors Affecting Coal Delivery Mode

What are the factors affecting the modes by which coal will be shipped? First, there is the basic cost factor, expressed as dollars per ton or cents per ton-mile. Given the more rapid relative development of large open-pit mining operations in the West and, to a much lesser extent, underground western mining operations, a premium is arising on the ability to move large quantities of coal long distances. The first candidates which come to mind when considering very long distance hauling of coal are dedicated, or unit, trains and slurry pipelines. Campbell and Katell, in their 1975 report for the Bureau of Mines, do provide some estimates of the comparable modal costs. They point out that, for similar volumes of coal, the cost per ton mile varies between 3 and 7 mills for slurry pipelines, and 4 and 9 mills for unit trains. This comparison only serves to tell us that there will probably have to be features or conditions unique to each case before a decision on which mode to select can be made. Both modes require long-term commitments on the part of coal users, yet both have features which recommend them. A slurry pipeline, once installed, will prove to be highly resistant to inflation in operating costs, simply because its operating costs are minimal. The railroads cannot make this claim. Reliability of service provides another point of distinction between the two modes. The two existing slurry pipelines -- in Ohio and Arizona -- have been available for operation over

98% of the time. No railroad has provided this degree of reliability. Where flexibility of route and scheduling is desired, the railroad is the mode of choice.

Not all coal will be shipped very long distances. In fact, over three-quarters of our coal will still be coming from eastern surface and underground mines in 1985. There is likely to be a greater variety in the size of these mining operations, as well as a greater variety in the distances between the mine and the final consumer. In this situation, the cost factors favor trucks, conveyors, non-unit trains and barges. In the same study by Campbell and Katell, the costs for truck and conveyor belt for very short distances (less than 15 miles in the case of conveyors, and, not specified but quite likely less than, 100 miles for trucks) were about equal to the costs for unit trains and slurries on a cents per ton-mile basis. The average cost per ton-mile for barges was the lowest for any mode examined. Data obtained from the National Energy Transportation Study recently completed by the Congressional Research Service indicated a modal cost of just over 3 mills for an average trip of 480 miles. Obviously, the limiting factor in the use of barges is the availability of usable rivers and canals. The bulk of the coal, however, in 1985 will still be carried by the railroads. They are second only to trucks in terms of flexibility, and they provide the best unit costs for the medium tonnages and distances which will be encountered in bringing eastern coal to eastern users.

There are other factors which affect the choice of coal transportation modes.

There are political factors which affect the choice of mode. I believe the issue of eminent domain will be resolved at the national level in favor of the slurry pipeline interests. The question of economics is not a stumbling block; the railroads have even agreed that building a slurry pipeline is cheaper than laying a new rail line.

The problem of water is at the heart of the controversy. The use of the West's limited water supply will be the last political issue to be resolved in the matter of slurry pipelines. A smaller parallel line could carry the water back from Arkansas to Wyoming to be re-used. This would minimize the amount of water used in the slurry, and solve the problem of what to do with 20,000 acre feet of almost unreclaimable water.

Another political factor concerns such environmental constraints as sulfur emission standards and surface mine reclamation standards. According to a number of studies, the impact of the surface mine legislation will, among other things, reduce coal output in Appalachia by tens of millions of tons below what it otherwise would have been. The likely effect of this would be to increase the modal shares accounted for by unit trains and slurry pipelines in the west. To the extent that demand for low-sulfur coal increases relative to the demand for all coal, this, too, bodes well for the owners and operators of unit trains. The impact on truck hauling and short-haul rail operations of a drop in demand for medium to high sulfur coals would not be insignificant.

There are also structural factors involved in determining the mode of shipment. One structural factor which should be mentioned is ownership of coal reserves. The railroads have the largest coal reserve base in private ownership. The oil and gas companies are estimated to hold the next largest share, and coal-consuming industries such as the steel, electric utility and chemical companies are next. The implications of this pattern of ownership would tend to confirm an already sound view that the railroads will continue to dominate the coal hauling business.

Transportation Equipment Requirements and Cost

Can we supply the facilities and equipment required to move the coal?

For estimates of the equipment requirements, we have several recent reports to draw on. The first report is "Coal Transportation Practices and Equipment Requirements to 1985," written by Gary Larwood and David Benson of the Bureau of Mines. The authors assume that 1.2 billion tons of coal will need to be moved in 1985. According to their study, the railroads will be required to carry between 894 million and 945 million tons of coal. To do this would require between 126,000 and 142,000 hopper cars or about 1,260 to 1,420 unit trains in 1985. A report prepared by Bechtel Research & Engineering for the Office of Energy Programs projected a requirement for the equivalent of about 700 unit trains in 1985.

The third report is the "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond" prepared by Manalytics, Inc., for the Electric Power Research Institute in September of 1976. Two scenarios were prepared. In the first, it was assumed that 1.5 billion tons of coal would be moved by rail in 1985; in the second, it was assumed that 1.24 billion tons would be shipped by rail. The rolling stock required for these amounts is projected to be the equivalent of 1,947 unit trains and 2,129 unit trains for the first and second scenarios, respectively. Manalytics estimated the number of locomotives required to be 9,735 and 10,645 in the first and second scenarios, respectively. Larwood and Benson estimated the number of locomotives required to be between 6,900 and 7,800.

Considering the number of barges which will be needed in 1985, Larwood and Benson projected that between 1,800 and 3,400 barges of 1,400 ton equivalent will be required to move the barge share of coal traffic. The Office of Energy Programs report, converted to 1,400 ton equivalent units, puts this figure at just over 3,000 barges.

How much is all of this equipment going to cost? We have the estimates of two companies. The first is the Bechtel Corporation and the second is the Bankers Trust Company. Both estimates cover the years 1976-1985, inclusive, and are expressed in 1974 dollars.

The Bechtel Corporation estimates that approximately $8.8 billion will be required to design, construct and start up transportation facilities. Bankers Trust Company projects that about $10.25 billion will be required to provide the same services. Both estimates show expenditures beginning at around three quarters of a billion dollars in the late 1970's, and peaking in 1985 at $1.1 billion and $1.2 billion, respectively.

Modal Share Estimates

It is clear that there will not be any very large shifts in the share of coal hauled by a particular mode. Rail traffic, which in the first quarter of 1977 moved half of the coal shipped, will likely increase its share of the volume as western mining comes into its own and the increased use of unit trains thus lowers unit shipping costs. The Federal Power Commission, in January of this year, released a staff study which estimated the modal shares for coal delivered to new coal-fired electric utility units coming on stream between now and 1985. The railroads' share of this traffic is estimated by the FPC to be about 66% in 1980 and 62% in 1985.

River traffic, which accounted for 15% of coal moved in the first quarter of 1977, is projected by the FPC to carry 9% of the coal required by new coal-fired utilities in 1980, and just over 6% of the coal required in 1985.

The FPC projects a large increase in the share of truck traffic bringing coal to new generating facilities relative to its current level. In the first quarter of 1977, trucks hauled over 13% of all coal; in 1980 and 1985, trucks are projected to account for about 22% of all shipments to new coal-fired facilities. The single greatest cause of this rise in modal share is probably the increase in the number of mine-mouth electric generating plants which are expected to come on stream.

The remainder of the coal-carrying modes -- conveyors, pipelines, etc. -- will have their shares affected little, if at all, although the actual absolute tonnages they carry may increase dramatically.

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COAL DESULFURIZATION TEST PLANT STATUS - JULY 1977

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I. INTRODUCTION

An 8 metric ton/day process test plant for chemical desulfurization of coal has just been built at TRW's Capistrano Test Site in California. The plant, shown in Figures 1 and 2, was constructed under an Environmental Protection Agency sponsored project for the development of the Meyers Process. Current plans call for plant shakedown followed by processing of 100-200 tons of American Electric Power Service Corporation's Martinka Mine coal.

The Meyers Process removes up to 80 percent of the total sulfur content of coal through chemical leaching of 90 to 95 percent of the pyritic sulfur contained in the coal matrix with aqueous sulfate solution at temperatures of 90° to 130°C. The ferric sulfate content of the leach solution is regenerated at similar temperatures using air or oxygen, and elemental sulfur and iron sulfates are recovered as reaction products or alternatively gypsum can replace all or a portion of the iron sulfates as a product. The physical form of the coal remains unchanged; only pyrite and some inorganic materials are removed.

Low and medium organic sulfur coal can be desulfurized prior to combustion using the Meyers Process (1,2) to meet governmental requirements for sulfur oxide emissions.

The Environmental Protection Agency estimates that 90 x 10^9 tons (80 x 10^9 metric tons) of coal reserves in the U.S. Appalachian Coal Basin can be reduced in sulfur content by the Meyers Process to levels which will meet New Source Performance Standards. Successful bench-scale testing (3,4) and promising engineering analyses (3,5-7) together with applicability testing (8,9), have led the Environmental Protection Agency to sponsor the construction and operation of a test plant.

Present estimated processing costs using utility financed depreciation of capital, and including coal grinding and compaction of the product (where necessary), are $8-12/ton (3,6). The price varies within this range according to factors such as offsite, coal pre-cleaning, reaction rate of the particular coal and coal top-size utilized, i.e., 3/8" processing and pre-cleaning of run-of-mine coal contribute to lower cost. Recent advances, which have not yet been fully designed, promise to reduce the above costs.

Process chemistry, and test plant design and operation will be described below.

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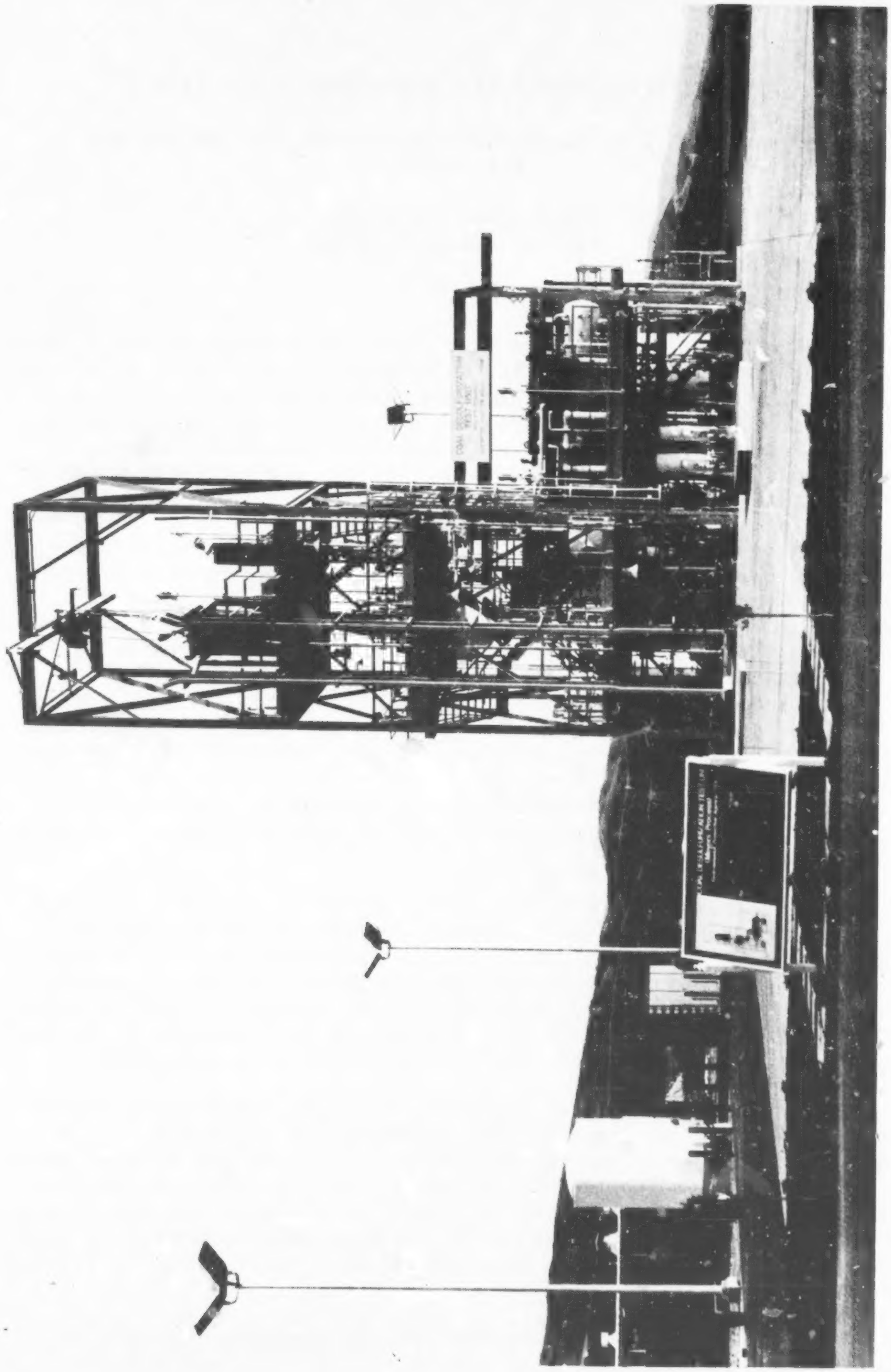

Figure 1. Test Plant - Front View

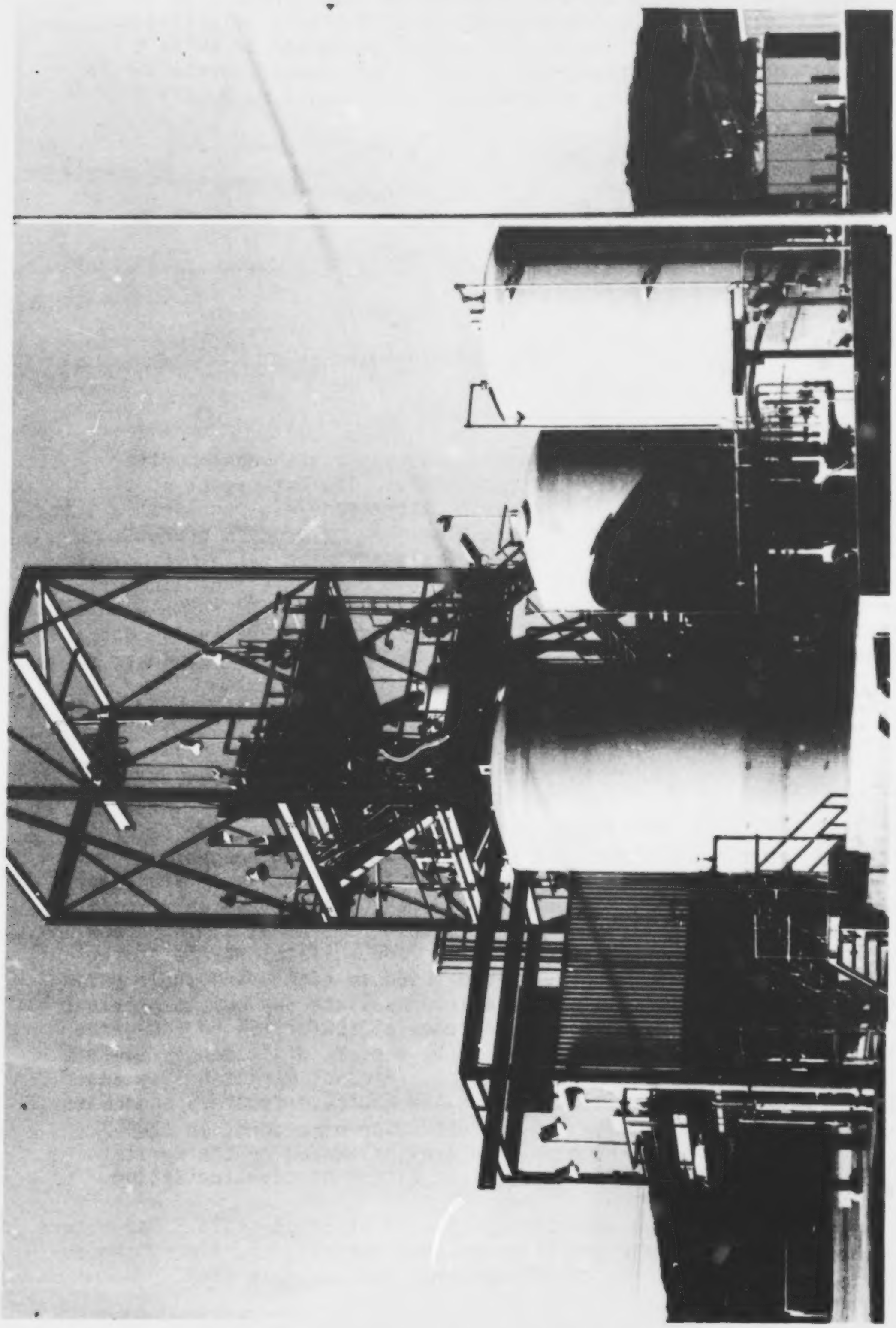

Figure 2. Test Plant - View Through Tank Farm

II. PROCESS CHEMISTRY, KINETICS AND SCHEME

The process is based on the oxidation of coal pyrite with ferric sulfate (Equation 1). The leaching reaction is highly selective to pyrite with 60 percent of the pyritic sulfur converted to sulfate sulfur and 40 percent to elemental sulfur. The reduced ferric ion is regenerated by oxygen or air according to Equations 2 or 3.

$$\begin{aligned} &FeS_2 + 4.6\ Fe_2(SO_4)_3 + 4.8\ H_2O \rightarrow \\ &\quad 10.2\ FeSO_4 + 4.8\ H_2SO_4 + 0.8S \end{aligned} \tag*{1)}$$

$$\begin{aligned} &2.4\ O_2 + 9.6\ FeSO_4 + 4.8\ H_2SO_4 \rightarrow \\ &\quad 4.8\ Fe_2(SO_4)_3 + 4.8\ H_2O \end{aligned} \tag*{2)}$$

$$\begin{aligned} &2.3\ O_2 + 9.2\ FeSO_4 + 4.6\ H_2SO_4 \rightarrow \\ &\quad 4.6\ Fe_2(SO_4)_3 + 4.6\ H_2O \end{aligned} \tag*{3)}$$

Regeneration can be performed either concurrently with coal pyrite leaching in a single operation or separately. The net effect of the process is the oxidation of pyrite with oxygen to yield recoverable iron, sulfate sulfur, and elemental sulfur. The form of process products varies to some extent with the degree of regeneration performed. Thus, Equations 1 and 2 lead to the overall process chemistry indicated by Equation 4 with products being a mixture of iron sulfates and elemental sulfur. Equations 1 and 3 yield ferrous sulfate, sulfuric acid, and elemental sulfur as indicated by Equation 5.

$$FeS_2 + 2.4\ O_2 \rightarrow 0.6\ FeSO_4 + 0.2\ Fe_2(SO_4)_3 + 0.8S \tag*{4)}$$

$$FeS_2 + 2.3\ O_2 + 0.2\ H_2O \rightarrow FeSO_4 + 0.2\ H_2SO_4 + 0.8S \tag*{5)}$$

Several options exist in product recovery. Iron sulfates may be recovered as pure solids by stepwise evaporation of a spent reagent slipstream with ferrous sulfate being recovered first because of its lower solubility. Alternately, ferrous sulfate may be recovered by crystallization, and ferric sulfate or sulfuric acid removed by liming spent reagent or spent wash water slipstreams. Iron sulfates may be stored as solids for sale or may easily be converted to highly insoluble basic iron sulfates (by air oxidation) or calcium sulfate (by low-temperature solid phase reaction) for disposal. Elemental sulfur may be recovered from coal by vaporization with steam or by vacuum, or it can be leached out with organic solvents such as acetone. Product marketability and product recovery economics will dictate the choice. Recovery economics may be influenced by quantity and concentration of product in the process effluent streams which in turn are influenced by the pyrite concentration in the coal and the desired extent of desulfurization.

The process has been extensively studied at bench-scale. Parameters investigated included coal top-size, reagent composition, slurry concentration, reaction temperature and pressure, and reaction time.

Additional investigations completed or underway include concurrent coal leaching-reagent regeneration, product recovery, product stability, and the effect of coal physical cleaning on process performance and economics. The process scheme depicted in Figure 3 is based on the bench-scale testing. Coal is a) crushed to the desired size for processing, b) contacted with hot recycled reagent in the Mixer (90-100°C), c) leached of pyrite in the Reactor(s) with simultaneous or separate reagent regeneration, d) washed with hot water, and e) stripped of elemental sulfur, dried and finally cooled. The iron and sulfate sulfur are recovered from spent reagent slipstreams prior to reagent recycle. Figure 4 shows typical data on pyrite removal rates from Appalachian coal as a function of temperature. Removal of 10-20 percent of the pyrite is obtained during slurry mixing and heat-up.

Bench-scale data indicated that the pyrite leaching rate from coal can be adequately represented by the empirical rate expression (Equation 6).

$$r_L = -\frac{dWp}{dt} = K_L W_P^2 Y^2 \qquad 6)$$

where

$K_L = A_L \exp(-E_L/RT)$,

Wp = wt percent pyrite in coal,

Y = ferric ion-to-total iron ratio in the reactor reagent, and

A_L and E_L are constants for each coal and particle size at least over most of the reaction range.

The leach rate is a function of coal type. Pyrite extraction rates vary considerably, as detailed in a study of the Meyers Process as applied to U.S. coal (8), e.g., there was more than one order of magnitude difference between the fastest and slowest reacting coal. The reagent regeneration rate is governed by the rate expression (Equation 7).

$$r_R = -\frac{dFe^{+2}}{dt} = K_R P_{O_2} (Fe^{+2})^2 \qquad 7)$$

where

$K_R = A_R \exp(-E_R/RT)$,

P_{O_2} = oxygen partial pressure,

Fe^{+2} = ferrous ion concentration in the reagent solution, and

A_R and E_R are constants.

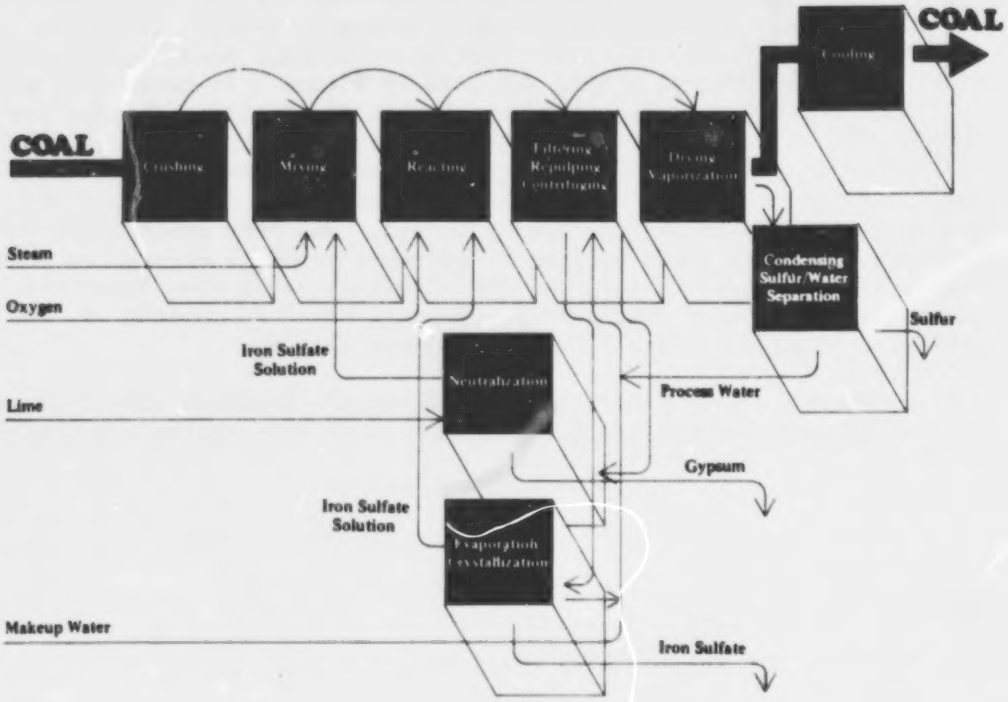
COAL
Crushing
Mixing
Reacting
Filtering
Repulping
Centrifuging
Drying
Vaporization
Cooling
COAL
Steam
Oxygen
Condensing
Sulfur/Water
Separation
Sulfur
Iron Sulfate
Solution
Neutralization
Process Water
Lime
Gypsum
Iron Sulfate
Solution
Evaporation
Crystallization
Makeup Water
Iron Sulfate

Figure 3. Process Flow Schematic

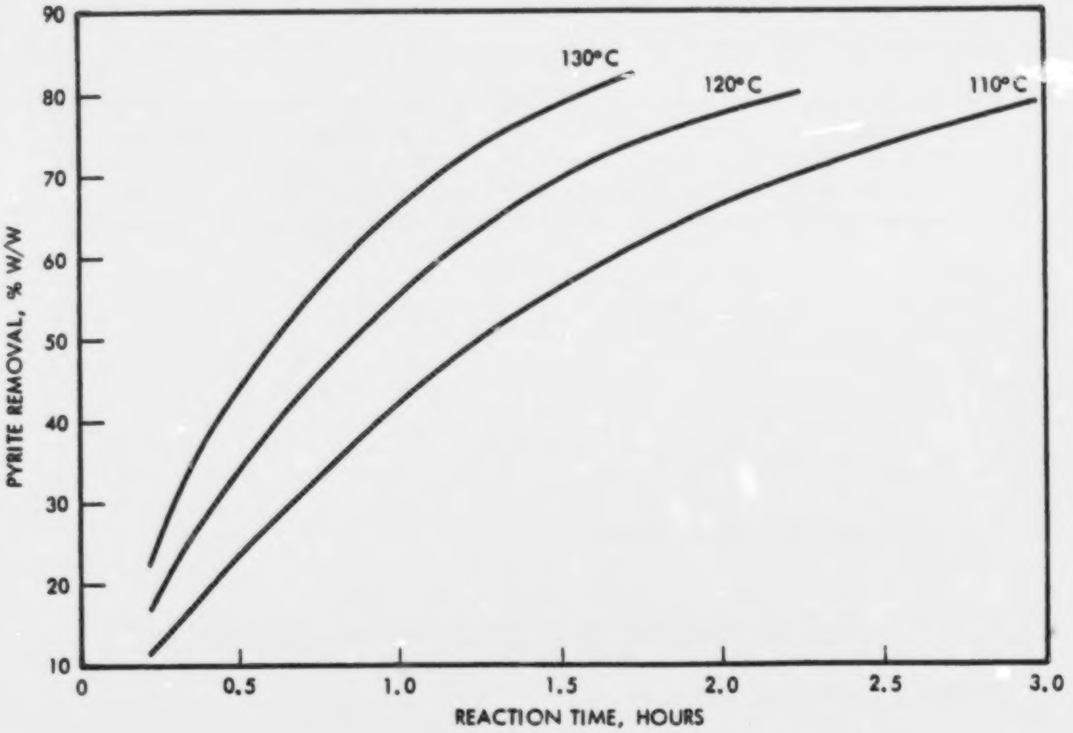

Figure 4. Temperature Effect on Processing of 14 Mesh Top-Size Lower Kittanning Coal (33% w/w Slurries)

Engineering evaluation of available data shows that it is preferable to process fine coal (<2 mm top-size) under simultaneous leaching-regeneration conditions in the temperature range of 110-130°C until the majority of the pyrite is leached out. Ambient pressure processing (approximately 100°C) is indicated for the removal of the last few tenths percent of pyrite since the low Wp value substantially reduces the rate of ferric ion consumption and, therefore, the need for simultaneous reagent regeneration. Ambient pressure processing appears to be indicated also for coarse coal (e.g., 10 millimeter top-size) for several reasons. It is difficult to continuously feed a non-slurryable coal into and remove it from a pressure vessel. It is much easier and less costly to drain leach solution from the coal and pump it into a small pressure vessel for regeneration. Also the slower reaction rate with coarse coal would require much longer residence times and unreasonably large total volume for pressure vessels. These engineering evaluations were part of the data used to design the test plant.

III. TEST PLANT DESIGN AND OPERATION

A test plant sized to process up to 8 metric tons per day of coal has been built, under the sponsorship of the Environmental Protection Agency, at TRW's Capistrano Test Site. A plant flow diagram is shown in Figure 5. The facility is capable of on-line evaluation of the following critical process operations:

- Pressure leaching of pyritic sulfur from 150 micron to 2 mm top-size coal at pressures up to 100 psig,

- Regeneration of ferric sulfate both separately, for processing larger top-size coal or low pyrite coal, and in a single vessel with the leaching step for processing of suspendable coal,

- Filtration of leach solution from reacted coal,

- Washing of residual iron sulfate from the coal.

Iron sulfate crystallization, elemental sulfur recovery and coal-drying unit operations will be evaluated in an off-line mode in equipment vendor pilot units. Leaching of 10 mm top-size coal can be evaluated in an off-line mode in an atmospheric pressure vessel installed in the test plant. Coarse coal processing (5-10 mm top-size) has been very promising in laboratory tests (3). If this approach proves out in bench-scale evaluations, more extensive and on-line coal leaching units can be readily added to the present test plant. Processing fine coal allows the highest rate of pyritic sulfur removal, while processing coarse coal, although slower, allows lower cost coal dewatering units and the direct shipping of desulfurized coal product without need for pelletizing.

The test plant constructed at the Capistrano Test Site is a highly flexible facility capable of testing the numerous alternate processing modes of potential interest in the Meyers Process. The flow diagram shown in Figure 3 presents an equipment train for continuous process testing of slurried coal. Fine coal ground to the desired size is

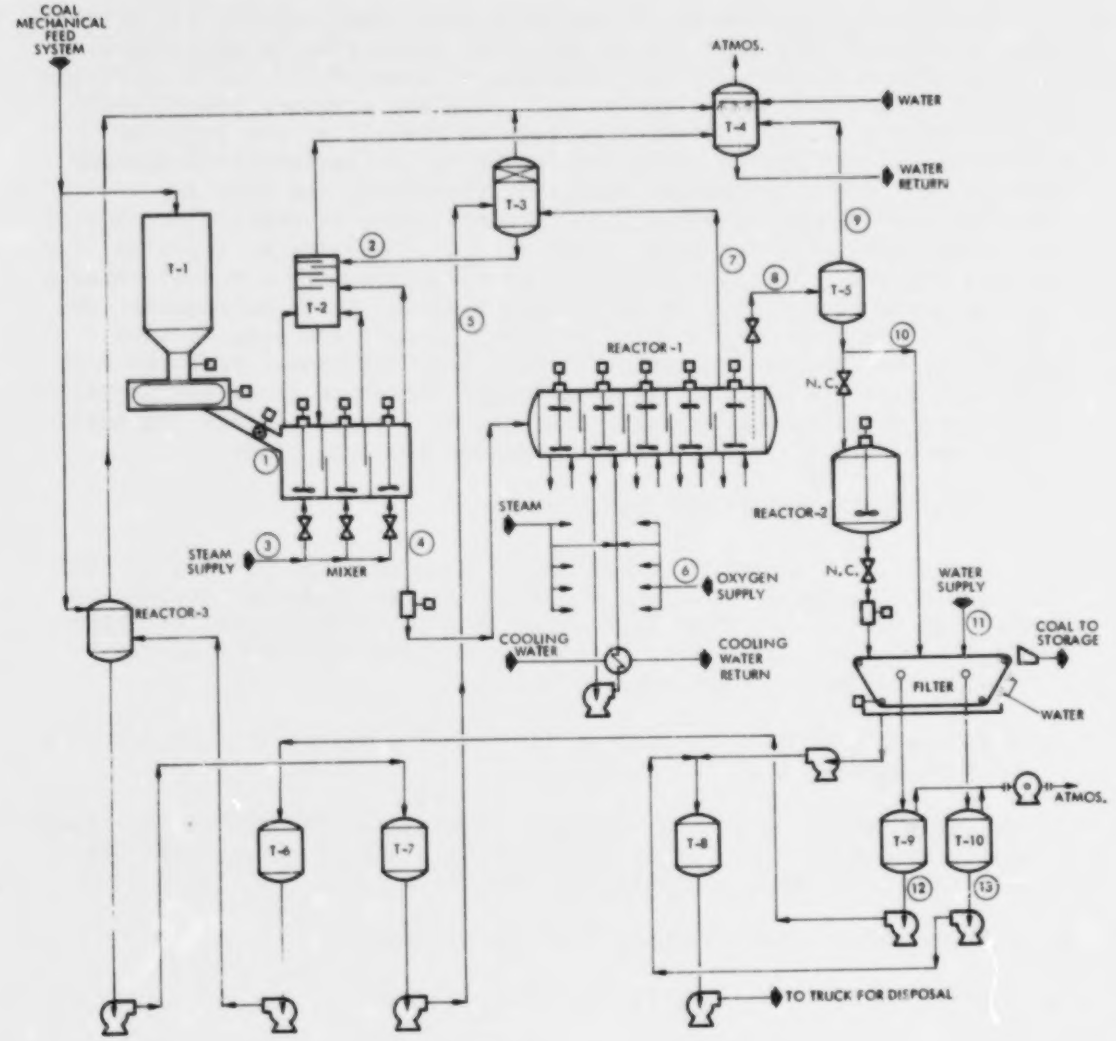
COAL MECHANICAL FEED SYSTEM
ATMOS.
WATER
T-4
WATER RETURN
T-1
T-3
T-2
2
5
7
8
9
T-5
10
REACTOR-1
N.C.
1
REACTOR-2
STEAM
STEAM SUPPLY
3
MIXER
4
6
OXYGEN SUPPLY
N.C.
WATER SUPPLY
11
COAL TO STORAGE
REACTOR-3
COOLING WATER
COOLING WATER RETURN
FILTER
WATER
ATMOS.
T-6
T-7
T-8
T-9
T-10
12
13
TO TRUCK FOR DISPOSAL

Figure 5. Test Plant Flow Diagram

stored under nitrogen gas in 1.8 metric ton sealed bins. As required, bins are emptied into the feed tank (T-1). Dry coal is continuously fed by a live bottom feeder to a weigh belt which discharges through a rotary valve to the three stage mixer (Stream 1). The aqueous iron sulfate leach solution (Stream 2) enters the mixer after first passing through a foam breaker (T-2). Steam is added (Stream 3) to raise the slurry to its boiling point. Foaming will occur in the early stages of mixing, but will cease when particle wetting is complete. It is believed that the mixing time and conditions necessary to complete the wetting and defoaming of the slurry will depend on the coal type and size and on the residual moisture in the feed coal. To allow study of the mixing parameters, the mixer stages have variable volume with variable speed agitators, and the feed flow rates for coal, leach solution and steam can be varied over wide ranges.

The defoamed slurry (Stream 4) is pumped to a five stage pressure vessel (Reactor 1) in which most of the pyrite removal reaction occurs. Some of the pyrite reaction occurs during mixing, but in the mixer the reaction rate slows rapidly because the remaining pyrite (Wp) decreases and because the ferric iron is rapidly being converted to ferrous iron (Y decreases). The pressure reactor overcomes the decreased rate in two ways. First, it increases the temperature (and pressure) to increase the reaction rate constant. Second, oxygen is introduced under pressure to regenerate ferric iron and maintain a high solution Y. The flow diagram shows that steam and oxygen can be added to any or all of the five stages and that cooling can be provided for any stage if necessary to remove the excess heat of reaction. The unused oxygen saturated with steam (Stream 7) is contacted in a small pressure vessel (T-3) with the feed leach solution (Stream 5) to provide heated leach solution for the mixer (Stream 2) and cooled vent gas. The vent gas from both T-2 and T-3 are scrubbed in T-4 to remove any traces of acid mist. The reaction parameters of importance have already been well studied at laboratory and bench-scale in batch mode. The test plant reactor will accommodate the necessary studies of key parameters in a continuous reactor at coal throughputs between 2 and 8 metric tons per day. Parameters which will be studied include temperature, pressure, oxygen purity, slurry concentration, iron sulfate concentration, iron sulfate concentration, acid concentration, residence time per stage, number of stages, mixing energy, type of mixing, coal size and type. The reactor can also be used to study leach solution regeneration in the absence of coal.

Reacted coal slurry (Stream 8) at elevated temperature and pressure is flashed into a gas-liquid separator vessel (T-5). The steam generated (Stream 9) is condensed in T-4 and the condensate plus any entrained acid mist is removed with the water. The residual slurry (Stream 10) is fed to a belt filter. The filtrate, which is regenerated leach solution, is removed from the coal slurry through a vacuum receiver (T-9) and pumped (Stream 12) to a large leach solution storage tank (T-6). The coal on the filter belt is washed with water (Stream 11) and discharged from the filter belt. The wash water is removed through a vacuum receiver (T-10) and sent to a large liquid-waste holding tank (T-8) for subsequent disposal. The filter is a highly versatile unit which should provide the data necessary for scale-up.

It has variable belt speed, variable belt areas assigned to washing, variable cake washing rates, belt sprays if needed to control blinding of the pores in the belt, and steam nozzles to provide for partial cake drying.

As an alternate process step, the slurry from the flash tank (T-5) can be passed into a secondary reaction vessel (Reactor 2). At typical coal feed rates, this vessel can be filled in about two hours and then closed off, stirred and heated for any desired period of time before being pumped to the filter. Residence times up to about 10 hours are available in the primary reactor, Reactor 1. This secondary reactor can be used to extend residence times to much longer times for examining the removal of final traces of pyrite or examining any other long term behavior. The stirred vessel also can serve to repulp the filter cake for additional coal washing studies.

The final item of major equipment in the test plant is the coarse coal contact vessel (Reactor 3). This insulated and heated tank will hold a full bin (about 1.8 metric tons) of coarse coal (5 to 10 millimeter top-size). The principal use for this vessel is to convert the regenerated leach solution in storage tank T-6 to a more depleted solution in the process feed tank, T-7. In general, the iron sulfate leach solution in the filtrate going to tank T-6 will have a high Y because no secondary reactor was in use. For some test conditions, the feed to the process must be at a lower Y to simulate recycle leach solution from a secondary reactor. Passing all or some portion of the solution through coal will lower the Y of the solution to the desired value. This vessel is basically a coarse coal reactor and if appropriate sampling ports and possibly some flow distribution internals were added, it could be used to obtain design data for coarse coal processing.

Solution tanks are sized at about 50,000 liters to provide for about a week of continuous operation on the same feed without recycle or change. It also provides for uniform leach solution and coal samples of a large enough size for product recovery studies performed by equipment vendors. Operation at the scale of the test plant will provide experience and data expected to be adequate for the design of a demonstration-size commercial plant.

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STATUS AND PROBLEMS IN THE DEVELOPMENT OF HIGH GRADIENT MAGNETIC SEPARATION (HGMS) PROCESSES APPLIED TO COAL BENEFICIATION*

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ABSTRACT

An overall discussion of the status and problems in the development of HGMS processes applied to coal beneficiation is presented. Included in the discussion are such topics as: bench-scale and pilot-scale experimental studies; quantitative modeling of experimental results; conceptual process design and cost estimation; and comparison with alternate technologies for coal beneficiation. The needs and opportunities in the future research and development work related to magnetic beneficiation of coal are also suggested.

INTRODUCTION

High gradient magnetic separation (HGMS) is a new technology which provides a practical means for separating micron-size, feebly magnetic materials on a large scale and at much faster flow rates than are possible in ordinary filtration. The technology is also applicable to separating nonmagnetic materials which can be made to associate with magnetic seeding materials. It was developed in 1969 for the wet separation of weakly magnetic contaminants from kaolin clay[1-6]. A typical HGMS unit for this wet application is shown schematically as Figure 1. The electromagnet structure consists of energizing coils and a surrounding iron enclosure. The coils in turn enclose a cylindrical working volume packed with fine strands of strongly ferromagnetic packing materials such as ferritic stainless steel wool. With this design, a strong field intensity up to 20 kOe can be generated and distributed uniformly throughout the working volume. Furthermore, by placing in the uniform field the ferromagnetic packing materials which increase and distort the field in their vicinity, large field gradients of the order of 1-10 kOe/μm can be produced. In the wet beneficiation of kaolin clay, the HGMS unit is used in a batch or cyclically operated process like a filter. The kaolin feed containing the feebly magnetic

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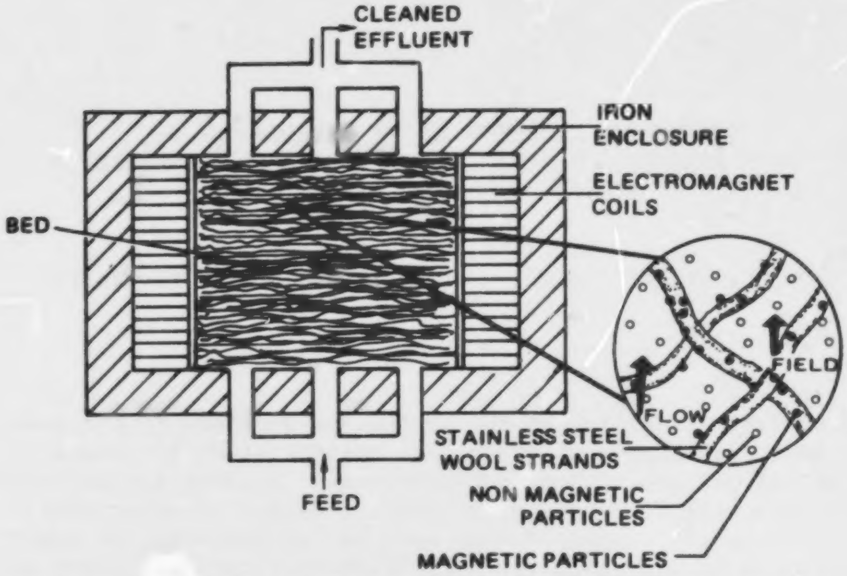

Figure 1. Cyclic High Gradient Magnetic Separator[5]

contaminants of low concentrations is pumped through the stainless steel wool packing or matrix of the separator from the bottom while the magnet is on. The magnetic materials (mags) are captured and retained inside the separator matrix, and the nonmagnetic components (tails) pass through the separator matrix and are collected as the beneficiated products from the top of the magnet. After some time of operation, the separator matrix is filled to its loading capacity. The feed is then stopped, and the separator matrix is rinsed with water. Finally, the magnet is turned off, and the mags retained inside the separator matrix are backwashed with water and collected. The whole procedure is repeated in a cyclic fashion. The significance of HGMS, and its latest engineering and commercial development have been adequately discussed elsewhere[1-6].

Because of its very low costs and outstanding technical performance demonstrated in the kaolin application, HGMS was recently adapted to solving many separation problems related to minerals and chemical processing industries. An important and promising application of HGMS is the magnetic removal of inorganic sulfur and ash from coal. Previous experimental investigations have indicated clearly that most of the mineral impurities in coal which contribute to its pyritic sulfur, the sulfate sulfur and the ash content are paramagnetic. These sulfur-bearing and ash-forming minerals, if sufficiently liberated as discrete particles, can be separated normally from the pulverized diamagnetic coal by magnetic means[7-8]. Indeed, the technical feasibility of applying HGMS to the beneficiation of pulverized coal suspended in water has been demonstrated in a number of recent studies, with substantial amounts of sulfur and ash removal reported[8-12]. Recently, a bench-scale feasibility study of utilizing a novel air-fluidized separator matrix in HGMS applied to the beneficiation of the dry pulverized coal was conducted in the authors' laboratory in cooperation with Oak Ridge National Laboratory. The available results from this study were quite encouraging, indicating that a dry HGMS process for coal beneficiation with performance comparable to the wet magnetic approach could be developed at much cheaper cost.[13]

In this paper, an overall discussion of the recent development and current status of HGMS processes applied to coal beneficiation is presented. A quantitative assessment of the technical and economical feasibility of applying HGMS to remove sulfur and ash from both dry and wet coals is given. In particular, because of its more advanced state of development, the magnetic beneficiation of water slurries of pulverized coals is discussed in some detail. The needs and opportunities in the future research and development work related to magnetic beneficiation of coal are also suggested.

MAGNETIC BENEFICIATION OF COAL/WATER SLURRY

Process Description.[14] A conceptual process for the magnetic beneficiation of pulverized coal suspended in water by HGMS is shown schematically in Figure 2.

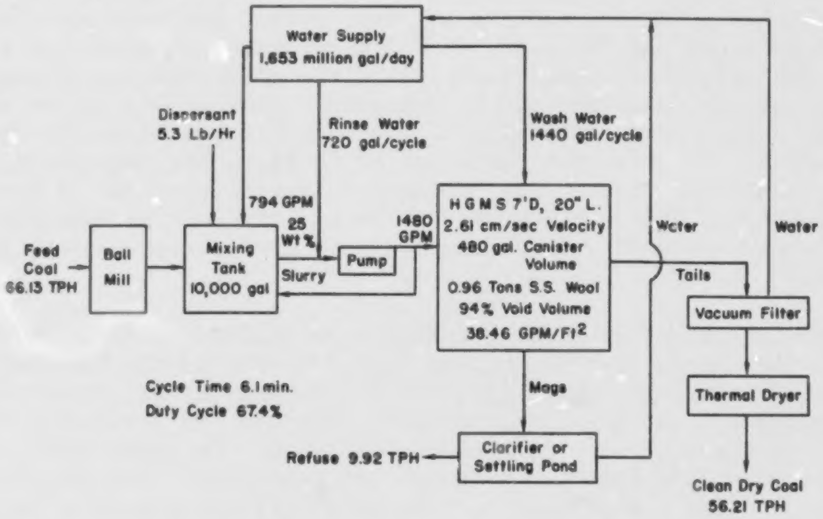
Water Supply
1,653 million gal/day
Dispersant
5.3 Lb/Hr
Rinse Water
720 gal/cycle
Wash Water
1440 gal/cycle
794 GPM
25
Wt %
1480
GPM
H G M S 7'D, 20" L.
2.61 cm/sec Velocity
480 gal. Canister Volume
0.96 Tons S.S. Wool
94% Void Volume
38.46 GPM/Ft^2
Water
Water
Feed Coal 66.13 TPH
Ball Mill
Mixing Tank 10,000 gal
Slurry
Pump
Tails
Vacuum Filter
Thermal Dryer
Cycle Time 6.1 min.
Duty Cycle 67.4%
Mags
Refuse 9.92 TPH
Clarifier or Settling Pond
Clean Dry Coal
56.21 TPH

Figure 2. Magnetic Beneficiation of Coal/Water Slurry by HGMS

A coal slurry of a fixed concentration is prepared by mixing known amounts of pulverized coal, water and a dispersant (wetting agent) like Alconox. The HGMS unit used here is the largest commercial unit now in use for producing high-quality paper coating clays. It is operated at a fixed field intensity of 20 kOe generated in an open volume 7 ft in diameter and 20 in. long. A stainless steel wool separator matrix having 94% voids is placed in the open volume. The coal slurry is pumped through the energized separator matrix at a fixed retention time (flow velocity) until the matrix reaches its loading capacity. After rinsing with water, the mags are sent to a settling pond or a clarifier to recover water for re-use. The tails are collected, dewatered, and dried. The typical specifications of process streams are also included in Figure 2, and the detailed operating conditions for such a case are given in the Appendix.

Experimental Studies of Process Feasibility. HGMS was recently adapted in a bench-scale exploratory study to remove sulfur and ash from a finely pulverized Brazilian coal suspended in water.[11] Since then, other investigators have utilized pilot-scale HGMS units to desulfurize and deash water slurries of some pulverized Eastern U.S. coals. For example, results of pilot-scale studies that demonstrated the technical feasibility of the magnetic separation of sulfur and ash from water slurries of pulverized Illinois No. 6, Indiana No. 5 and No. 6, Kentucky No. 9/14, and Pennsylvania Upper Freeport and Lower Kittanning coals have been reported.[9,10,12,13,15] Depending upon the types of coal and the separation conditions used, the existing bench- and pilot-scale results have shown that the use of single-pass HGMS was effective in reducing the total sulfur by 40-55%, the ash by 30-45%, and the pyritic sulfur by 75-90%, while achieving a maximum recovery of the beneficiated coal of about 95%.[8,16] These available results have indicated also that both the grade and recovery of the separation can be enhanced generally with the use of a larger separator matrix or by the recycle of the tail products. Although the existing data have not yet established total deashing by magnetic means, there is some indication that by enhancing the magnetism of ash-forming minerals and by optimizing the separation conditions, etc., the effectiveness of magnetic separation of ash from coal can be improved. Further discussion of the reported experimental results of the magnetic beneficiation of water slurries of pulverized coals can be found in the literature.[8] Also, the published Proceedings of Magnetic Desulfurization of Coal Symposium held at Auburn University in March, 1976 can be used for ready reference on HGMS and its experimental application to coal beneficiation.[16]

Quantitative Modeling and Prediction of Separation Performance. An important and latest breakthrough in applying HGMS to the beneficiation of coal/water slurry is the successful development of the conceptual understanding and the quantitative model required for predicting the technical performance of pilot-scale separation. In particular, the use of an experimentally verified mathematical model developed in the authors' laboratory[6,15] has now allowed one to quantitatively identify the trade-off of separation variables so as to optimize the magnetic removal of sulfur and ash from coal. Also, the model can be used to assess the technical and economical feasibility of the magnetic beneficiation of coal without extensive trial-and-error testing. In order to stimulate a more systematic approach to the future development of HGMS processes applied to coal beneficiation, some new insights on the quantitative aspects of magnetic beneficiation of pulverized coal in water are briefly discussed below.

The technical performance of a HGMS is generally characterized by the grade and recovery of the separated product, and by the capacity of the separator. When applying HGMS to beneficiating a fixed amount of pulverized feed coal of known sulfur and ash contents, the grade may be represented by the sulfur and ash contents in the beneficiated coal; while the recovery may be specified by the amount of the beneficiated coal. The capacity of a separator in the magnetic beneficiation of coal may be characterized by the amount of coal processed from the start of the separation until the instantaneous sulfur and ash contents of the beneficiated coal reach a prespecified percentage of the known sulfur and ash contents of the feed. In particular, the instantaneous change in effluent sulfur and ash contents with time, the so-called breakthrough curve, can be used to determine the processing time after which a separator is loaded. Here, a separator is said to be loaded if the effluent sulfur and ash contents of the coal to be beneficiated remain practically unchanged.

There are a number of important considerations involved in the quantitative modeling and prediction of the technical performance of HGMS applied to coal beneficiation. The first one is related to the particle trajectory and buildup. Specifically, the technical performance of an HGMS depends on how efficiently it captures magnetic particles, and how much of the captured particles can be retained in the separator matrix. The capture of magnetic particles by HGMS has recently been studied theoretically by using the equations of motion of magnetic particles flowing around a single magnetized, ferromagnetic collecting wire, and the performance of an ideal, unloaded HGMS composed of many such wires in the separator matrix is then related to the particle trajectories computed from the specified separation conditions.[2,17] Preliminary efforts have also been made to examine both theoretically and experimentally the effects of particle buildup or matrix loading on the performance of a nonideal, partially loaded HGMS.[6] However, none of the existing models based on the recent analyses of particle trajectory and buildup has been shown to be applicable to quantitatively predicting the effects of separation variables on the technical performance observed in pilot-scale experimental studies of HGMS. The next important consideration is the characteristic of the feed stream to be magnetically beneficiated. In the literature, most of the reported modeling and experimental studies of HGMS have been limited only to the feed streams containing either pure magnetic particles or simple mixtures of magnetic and nonmagnetic particles of approximately monodispersed or narrowly distributed sizes. However, little attention has been devoted to relating the technical performance of HGMS to the characteristics of the feed stream containing particles of a wide range of sizes, densities and magnetic susceptibilities as found in the magnetic beneficiation of coal. The third, but relatively less important, consideration is related to the mechanical entrapment or filtration of particles at low or zero field intensity. For separations at high field intensity, however, the effects of mechanical entrapment on the technical performance of HGMS are often considered to be negligible. In the recent work from the authors' laboratory,[6,15] the technical performance of HGMS has been quantitatively examined with reference to the above major considerations. Two practical observations of importance in the modeling of HGMS applied to coal beneficiation resulted from this work can be summarized as follows.

(1) The technical performance of HGMS is quantitatively related to the particle trajectory (or capture) and buildup. Under the presently used or proposed conditions for wet HGMS processes, however, the capability of the wire matrix to capture magnetic particles remains practically unchanged and essentially all magnetic particles are captured before the matrix is saturated or loaded with the buildup of particles. As a result, there is practically no need to calculate the trajectories of particles. The main factor in determining the technical performance of a pilot-scale or an industrial HGMS appears to be the particle buildup, but not the particle trajectory (or capture).

(2) Both the particle trajectory (or capture) and buildup are

highly dependent upon the ratio of the so-called magnetic velocity V_m of the particle to the free stream fluid velocity V_∞. In particular, the maximum amount of particle buildup on the wire increases with increasing value of V_m/V_∞; and there exists a minimum value of V_m/V_∞ for the captured particles to remain sticking to the wire matrix. Here, the magnetic velocity V_m is essentially a terminal velocity of a particle in a magnetic field, and it is defined by:

$$V_m = \frac{2\mu_o\ M\ H_o\ \chi\ R^2}{9\eta\ a} \qquad (1)$$

Except for the length L and packing void volume ε of the separator matrix, the ratio V_m/V_∞ contains almost all the major independent variables in HGMS, namely: (a) particle properties - radius R and magnetic susceptibility χ, (b) flow field - fluid viscosity η and free stream fluid velocity V_∞; (c) magnetic field - field intensity H_o and magnetization of wire M; and (d) separator matrix packing characteristics - wire radius a (and magnetization M). Under conditions of constant magnetic and flow fields as well as fixed separator matrix packing characteristics, the magnetic velocity is mainly a function of particle properties. In order to quantitatively relate the technical performance of HGMS to the characteristics of the feed stream containing particles of a wide range of sizes, densities and magnetic susceptibilities, it is necessary to determine the magnetic velocities of particles in the feed stream.

Based on the above findings, a simple particle buildup model incorporating the feed characteristics for predicting the technical performance of HGMS under the presently used or proposed conditions for wet HGMS processes has been developed by first calculating the minimum magnetic velocity for particle buildup, denoted by $V_{m,min}$. The latter is uniquely determined from the knowledge of the following process variables in HGMS: (a) (LOAD) - the total weight of captured magnetic particles per unit cross section of the separator matrix, (b) L - the length of the separator matrix, (c) F - the packed fraction of the separator matrix ($F = 1-\varepsilon$), (d) d - the apparent density of the particle buildup, and (e) V_∞ - the free stream fluid velocity. The specific details for calculating $V_{m,min}$ from these variables can be found in the literature [6,15]. Next, a so-called magnetic velocity distribution function for characterizing the feed stream, denoted by $F(V_m)$, can be introduced. Specifically, $F(V_m)$ represents the cumulative weight fraction of magnetic particles in the feed stream having a magnetic velocity less than V_m. Thus, if $V_m = V_{m,min}$, $F(V_m)$ corresponds to the cumulative weight fraction of magnetic particles in the feed stream which will not be captured inside the separator matrix. This result suggests that a simple particle buildup model for HGMS can be written as

$$\frac{C_{out}}{C_{in}} = F(V_m) \qquad V_m = V_{m,min} \qquad (2)$$

Here, C_{out} and C_{in} refer to the concentrations of the specific magnetic particles of interest, such as pyritic sulfur content in the magnetic beneficiation of coal, at the outlet and inlet of the separator matrix, respectively. Furthermore, a simple material balance of particles suggests that (LOAD) can be calculated from the total weight of feed particles per unit cross section of the separator matrix, (FEED), by integrating the following equation

$$\frac{d(\mathrm{LOAD})}{d(\mathrm{FEED})} = 1 - F(V_m) \qquad V_m = V_{m,\min} \qquad (4)$$

The magnetic velocity distribution, $F(V_m)$ is to be quantitatively determined by the experimental characterization of the feed stream. In the magnetic beneficiation of coal, for example, such a characterization requires the determination of particle size distribution, a standard float-and-sink separation, and measurements of the magnetic susceptibility along with the ash, sulfur and pyritic sulfur contents of each separated fraction. Specifically, suppose that $\chi(W)$ and $A_i(W)$ ($i=1,2$, and 3) are the magnetic susceptibility, and the ash, sulfur, and pyritic sulfur contents, respectively, of the pulverized feed coal at a cumulative weight percent W; and U(R) is the cumulative weight percent of particles having a radius smaller than R. Under conditions of constant magnetic and flow fields as well as fixed separator matrix packing characteristics, R can be related to the magnetic velocity of the feed stream V_m according to (1). Thus, in order for particles to have a magnetic velocity less than V_m, the radius of particles with a magnetic susceptibility χ should be smaller than

$$R = \left(\frac{9\ V_m\ \eta\ a}{2\ \mu_o\ M\ H_o\,\chi}\right)^{\frac{1}{2}}$$

The magnetic velocity distribution of the feed stream, $F(V_m)$, can then be obtained by

$$F(V_m) = \frac{1}{100}\left\{\int_{W_o}^{100} U\left\{\left(\frac{9\ V_m\ \eta\ a}{2\ \mu_o\ M\ H_o\,\chi}\right)^{\frac{1}{2}}\right\} dW + W_o\right\} \qquad (5)$$

Here, W_o is the weight percent of particles in the feed stream having negative magnetic susceptibilities. Note that implicitly included in (5) is the practical approximation that except by mechanical entrapment or filtration, no diamagnetic particles will be attracted magnetically by the wire matrix. Based on (5) and the measurements of ash, sulfur and pyritic sulfur contents of the pulverized feed coal, the specific magnetic velocity distributions of ash, sulfur and pyritic sulfur ($i=1,2$, and 3, respectively), denoted by $F_i(V_m)$, can be approximated by:

$$F_i(V_m) = \frac{1}{T_i}\left\{\int_{W_o}^{100} \left(\frac{A_i(W)}{100}\right) U\left\{\left(\frac{9\ V_m\ \eta\ a}{2\ \mu_o\ M\ H_o\ \chi(W)}\right)^{\frac{1}{2}}\right\} dW + A_{io} W_o\right\} \qquad (6)$$

In (6), T_i ($i=1,2$, and 3) are the average ash, sulfur and pyritic sulfur contents, respectively, of the pulverized feed coal; and A_{io} ($i=1,2$, and 3) are the average ash, sulfur and pyritic sulfur contents, respectively, of the fraction W_o with negative magnetic susceptibilities.

(1) - (6) represent the new mathematical model developed in the authors' laboratory for predicting the technical performance of HGMS

applied to coal beneficiation [6,15]. The model has been successfully applied to predict satisfactorily the grade, recovery, concentration breakthrough, etc., observed in pilot-scale experimental studies of HGMS applied to the beneficiation of water slurries of several pulverized coals such as Illinois No. 6, and Pennsylvania Upper Freeport and Lower Kittanning coals, etc. For example, Figure 3 illustrates the magnetic velocity distributions for coal, ash, sulfur and pyritic sulfur for characterizing the pulverized Illinois No. 6 coal under conditions of $H_o = 10^7/2\pi$ ampere-turn/meter (20 kOe), $M = 45 \times 10^6$ ampere-turn/meter (1.4 kOe), $\mu_o = 4\pi \times 10^7$ henry/meter, $a = 45 \times 10^{-6}$ m and $\eta = 10^{-3}$ kg/m-sec. These conditions correspond to the typical separation conditions for the experimental results reported in Ref. 9.

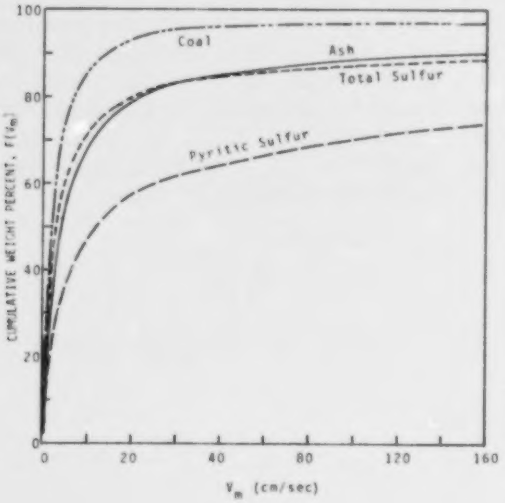

Figure 3. Magnetic Velocity Distributions of Pulverized Illinois No. 6 Coal

Figure 4 shows the typical comparison between the theoretical and experimental concentration ratios, C_{out}/C_{in}, of pulverized Illinois No. 6 coal particles in tail products obtained at a field intensity $H_o = 20$ kOe, a superficial slurry velocity $V_o = 1.86$ cm/sec, and different total feed rates per unit cross section of a pilot-scale HGMS. The comparison indicates that concentration ratios predicted by the model are in a reasonable agreement with experimental results. In Figure 5, a typical comparison between theoretical and experimental concentration breakthrough curves is illustrated. The curves in the figure are obtained by numerically integrating (3) based on the same feed characteristics and separation conditions as in Figure 4. It can be seen that there is also a reasonable agreement between theoretical and experimental concentration breakthrough curves. Note that there is no free parameter included in the new model given by (1) to (6). Also, the distributions of magnetic susceptibility, particle size and density along with ash, sulfur and pyritic sulfur contents of each separated fraction of the pulverized feed coal after the standard float-and-sink separation can all be easily measured experimentally prior to

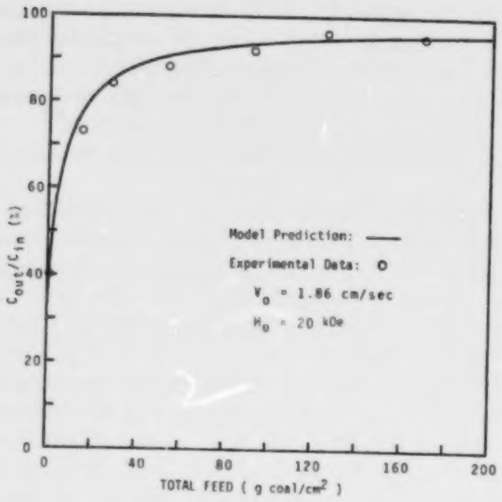

Figure 4. Theoretical and Experimental Concentrations of Coal Particles in Tails as a Function of Total Feed

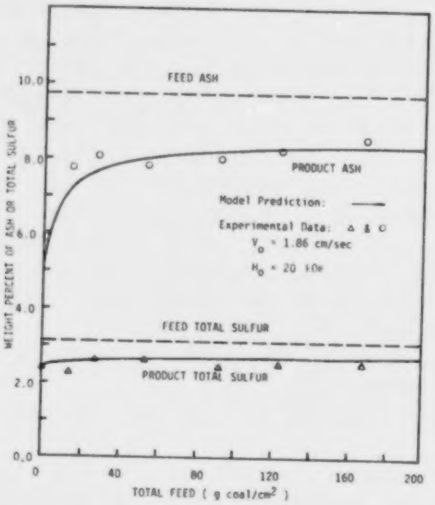

Figure 5. Theoretical and Experimental Ash and Sulfur Concentrations of Coal in Tails as a Funtion of Total Feed

actual magnetic separation testing. Thus, based on the above comparison between model predictions and experimental results for Illinois No. 6 coal, and the successful application of the model to several other Eastern U.S. coals described elsewhere[6,13,15], it can be suggested that *there is now an experimentally verified, simple model available for quantitatively predicting the grade, recovery, and concentration breakthrough, etc., in the magnetic beneficiation of water slurries of pulverized coals without actual HGMS testing.* By using the new model developed, it is possible to quantitatively determine the optimum separation conditions so as to optimize the magnetic removal of sulfur and ash, while achieving an economically acceptable recovery of the beneficiated coal. The new model can also be used to provide the needed information such as the proper separation duty cycle under the selected process conditions for the engineering design and cost estimation of wet HGMS processes applied to coal beneficiation[14]. Further discussion on the practical applications of the modeling results can be found in the literature[15].

Process Potential and Economics[14]. By removing 75-90% of the pyritic sulfur magnetically and achieving 85-90% recovery as was demonstrated by the results of reported studies of magnetic beneficiation of pulverized coals in water slurries,[8-15] the process illustrated in Figure 1 may be used to clean about one-fifth of the recoverable U.S. coals with a low organic sulfur content of 0.7-0.9 wt % to produce an environmentally acceptable fuel. A detailed documentation of the reserve and production of U.S. coals which may be magnetically cleanable to 1 wt% total sulfur according to the seam, district, and county in each state, along with the total and organic sulfur contents can be found in the literature[18]. A technical survey of such magnetically cleanable coals from Pennsylvania is currently being conducted in the authors' group in cooperation with the Coal Preparation and Analysis Laboratory of the U.S. Bureau of Mines.

Here, a reasonable range of add-on costs (excluding those for grinding, dewatering, drying and refuse disposal) can be estimated for the magnetic beneficiation of water slurries of pulverized coals which have desulfurization characteristics similar to those reported in the recent studies [8-15]. The method used to estimate the costs of magnetic desulfurization is based on the technique used by the Federal Power Commission Synthetic Gas-Coal Force to estimate the cost of synthesis gas[19,20]. The investor capitalization method used in this approach is the discount cash flow (DCF) financing method with assumed DCF rates of return such as 15% after taxes. This method essentially determines the annual revenue during the plant life which will generate a DCF equal to the total capital investment for the plant. Several assumptions are included in the method[19,20]:

(1) The plant life is assumed to be 20 years with no cash value at the end of life.
(2) A straight-line method is used to calculate the annual depreciation.
(3) Operating costs and working capital requirements are assumed to be constant during the construction period, and 100% equity capital is assumed.
(4) Total plant investment, return on investment during the plant life, and working capital are treated as capital costs in year zero (the year ending with the completion of start-up operations).
(5) Start-up costs are treated as an expense in year zero.
(6) 48% federal income tax is assumed.

Based on these assumptions, equations for calculating the unit costs ($ per ton of coal processed) are suggested by the published documents[19,20]. They are summarized in the Appendix, in which the detailed operating conditions and estimated costs for a typical example shown in Figure 1 are also given. The costs of major installed equipment and the unit costs listed in the Appendix are based on values of

June 1976. For instance, the costs of pump and tank used were estimated first according to Ref. 21 and then brought up to date by multiplying by the CE plant cost index ratio of (205/113.6), while the cost of the installed HGMS unit with a separator matrix of 7 ft in diameter and 20 in. long was estimated to be 1.936 million[23].

The estimated capital investment and unit costs for four typical cases, designated as A-D, are summarized in Table I. Slurry velocities of 2.61 and 4.0 cm/sec, slurry concentrations of 15, 25 and 35 wt%, as well as separation duty cycles of 59.0-77.9% are considered. These separation conditions illustrate clearly the effects of slurry velocity and concentration as well as separation duty cycle. For instance, comparison of cases A to C shows that at the same slurry velocity and similar magnetic desulfurization characteristics, the higher the slurry concentration, the cheaper will be the investment and unit costs. While this observation is to be expected, there have been pilot-scale tests which indicate that increasing the slurry concentration of pulverized Illinois No. 6 coal from 2.57 to 28.4 wt% did not appreciably change the grade and recovery of the separation[9]. Further effects of processing conditions, and other cost factors on the unit costs, are illustrated in Table II. It is seen from the table that by doubling the amount of coal processed per cycle relative to a fixed amount of stainless steel wool packed in the separator matrix, the unit cost can be reduced by about 15%. This result shows the importance of the separator matrix loading characteristics on the costs of magnetic desulfurization. Another factor which affects the unit costs considerably is the washing time required in a complete separation cycle. This is seen by comparing items 4 and 6 in Table II. In particular, the computed results indicated that doubling the amount of wash water required only leads to a negligible increase (0.27 - 0.60%) in unit costs. However, if both the amount of wash water and the washing time are doubled, the unit costs are increased by about 15%. The above observations clearly suggest an important economic incentive for further pilot-scale investigation of the separator matrix loading and washing characteristics in the magnetic beneficiation of coal/water slurry. Finally, item 7 of Table II shows that labor cost seems to be a significant fraction of the unit cost. Fortunately, it is not expected that the labor requirement will be doubled in actual commercial practice from the nominal case in Table I. This follows because existing experience in the commercial cleaning of kaolin clays by HGMS indicates that the labor requirements for both operation and maintenance are minimal[4,5,22].

A comparison of approximate estimated capital and unit costs of different pyritic sulfur removal processes currently under development[30,31] is given in Table III. With the exception of the MAGNEX process,[30] all the processes listed in Table III are wet cleaning methods and require grinding of feed coal, thus requiring relatively comparable grinding, dewatering, and drying costs. This table indicates that the costs of coal beneficiation by HGMS are attractive when compared with those of other approaches, even after adding the necessary costs of grinding, dewatering and drying. However, the above comparison is only an approximate one, because of the difference in the methods used to estimate the costs and in the desulfurization characteristics reported, etc. Based on the available cost information for these pyritic sulfur removal processes, it is not yet possible to carry out a rigorous comparison.

Table I. Cost of Desulfurization of Coal/Water Slurry by HGMS Using Separator Matrix of 7-Ft Diameter and 20-In Length

	Case A	Case B	Case C	Case D
1. Slurry velocity (cm/sec)	2.61	2.61	2.61	4.0
2. Slurry concentration (wt %)	15	25	35	25
3. Coal feed rate (ton/hr)	44.77	66.13	83.07	89.61
4. Cycle time (min)	9.00	6.10	4.85	4.50
5. Duty cycle (%)	77.9	67.4	59.0	59.6
6. Tons of coal processed per cycle	6.7	6.7	6.7	6.7
7. Unit costs ($ per ton coal processed)				
$\underline{U}$	2.083	2.369	1.109	1.067
$\underline{U}_o$	1.802	1.063	0.858	0.829
$\underline{U}_{15}$	3.676	2.412	1.967	1.880
8. Capital investment per ton coal processed per year ($)	6.93	4.69	3.73	3.53

Table II. Sensitivity Analysis of Unit Costs ($ Per Ton Coal Processed) of Desulfurization of Coal/Water Slurry by HGMS

	$\underline{U}_o$		$\underline{U}_{15}$	
	$	% Change	$	% Change
1. Basis: 2.61 cm/sec, 25 wt % slurry, and other conditions in the Appendix and Table I	1.0628	0.00	2.4117	0.00
2. Amount of coal processed per cycle doubled	0.9004	-15.28	2.0341	-15.66
3. 25% reduction in capital investment	0.9389	-11.26	2.0341	-19.12
4. Amount of wash water required doubled (washing time unchanged)	1.0691	+0.60	2.4181	+0.27
5. Coast of water increased 5/3 times (5c/1000 gal)	1.0835	+1.95	2.4324	+0.86
6. Both amounts of wash water and washing time doubled	1.2256	+15.32	2.7883	+15.62
7. Labor requirement doubled	1.3587	+27.82	2.7077	+19.12

Table III. Comparison of Estimated Approximate Capital and Unit Costs of Different Pyrite Removal Processes

Process	$\underline{U}_o$[a]	$\underline{U}_{15}$[a]	Capital Investment[b]
1. MAGNEX-Hazen Research, Inc.[24]	5.83	7.05	4.17
2. Froth flotation-Bureau of Mines[24]	2.77	4.47	5.71
3. Meyers-TRW Systems and Energy[25]	6.0-14.0		13.80 (leaching only)
4. Ledgemont oxygen leaching-Kennecott Copper Corp.[26]	comparable to Meyers		11.30 (leaching only)
5. HGMS-This work, see Table I	0.83-1.06	1.88-2.41	3.53-4.69

[a] Unit costs expressed in \$ per ton coal processed.
[b] Capital investment expressed in \$ per ton coal processed per year.

MAGNETIC BENEFICIATION OF DRY PULVERIZED COAL

The application of HGMS to remove sulfur and ash from dry pulverized coal has just been initiated recently. Much of the work reported thus far has been limited to investigating the technical feasibility of magnetic beneficiation of dry pulverized coal via either gravity feeding or air-entrained fluidization. Although some degree of magnetic removal of sulfur and ash was observed in using these approaches, the experimental results reported had not yet achieved separation performance comparable to those observed in magnetic beneficiation of coal/water slurry. In fact, the weight percent of sulfur removed from dry pulverized coal was rarely more than 10 to 20% even with multiple-pass separation. There was also no definitive indication in the existing reports[10,12] as to why dry beneficiation with either gravity feeding or air-entrained fluidization was less effective compared to wet separation. Quite recently, a joint experimental program on the high gradient magnetic beneficiation of dry pulverized coal has been initiated at Auburn University and Oak Ridge National Laboratory. Its objectives are to develop a novel recirculating air-fluidized separator matrix for use in HGMS applied to dry pulverized coal, and to compare the performance of both dry and wet HGMS processes for coal beneficiation. The available results from this research program have now provided some insights as to why wet separation was often successful, and dry separation with either gravity feeding or air-entrained fluidization thus far unsuccessful. Also, typical experimental results obtained with Pennsylvania Upper Freeport coal have indicated that *by using a recirculating air-fluidization approach, the performance of magnetic separation of sulfur and ash from dry pulverized coal can be even better than that from coal/water slurry.* The status and problems of this latest development of dry HGMS processes applied to coal beneficiation along with some important observations from other recent studies are briefly discussed below.[8,10,12,13]

Gravity Feeding Approach. The simplest way for feeding dry pulverized coal to a magnetic separator is by gravity. Preliminary results on the desulfurization of dry pulverized Indiana Nos. 5 and 6 coals by HGMS via gravity feeding reported in 1976 are summarized in Table IV.

Table IV. Magnetic Desulfurization of Dry and Wet Pulverized Indiana Coals via Gravity Feeding Approach[12]

	Sulfur Removal, % No. 5 Coal		Sulfur Removal, % No. 6. Coal	
	Dry[a]	Wet[b]	Dry[a]	Wet[b]
1. 1-Pass[c]	9.3	18.8	13.7	24.5
2. 2-Pass[c]	17.9	33.0	18.5	42.4
3. 3-Pass[c]	18.4	35.2	20.6	44.8

[a] 99% below 200 mesh, 20 kOe, Frantz screens

[b] 99% below 200 mesh, 20 kOe, stainless steel wool packing, 94% void, 30 wt% solids slurry.

[c] retention time per pass: 30 seconds

Also included in the table are their comparison with the results obtained by wet magnetic beneficiation.[12] There was no explanation given in Ref. 12 as to why wet beneficiation was more effective in sulfur removal compared to dry separation with gravity feeding as shown in the table. Some insights to answering the latter question can be provided by the recent experimental results obtained in the authors' laboratory.[12] Thus, by studying the magnetic desulfurization characteristics of dry pulverized coal of different particle size ranges, it was found that the use of feed coal of small particle sizes would often lead to the agglomeration of the pulverized coal and its mineral impurities. In order to minimize the occurrence of fine coal agglomeration which could impede magnetic beneficiation, it would not be desirable to use the feed coal ground to, for example, less than 100 to 200 mesh. This point may be illustrated by the experimental results given in Table V, in which the effect of particle size on magnetic desulfurization of Pennsylvania Lower Kittanning coal via gravity feeding is shown.[13] Essentially no sulfur was removed from the pulverized Lower Kittanning coal of particle sizes between 100 and 200 mesh; and actual agglomeration of coal and its mineral impurities was visually observed from the separated samples. In contrast, over 15% of the sulfur could be separated magnetically from the coal of particle sizes between 60 and 100 mesh. A major problem in using a moderately ground coal in dry separation, however, is that its sulfur-bearing and ash-forming minerals may not be sufficiently liberated; and there is a trade-off between avoiding fine coal agglomeration and grinding to liberate the mineral impurities in coal. In order to effectively apply HGMS for beneficiation of dry pulverized coal, it is necessary to closely examine the proper grinding level for a specific coal chosen at given separation conditions, while taking into account the desired liberation characteristics of its sulfur-bearing and ash-forming minerals.

Table V. Effect of Particle Size (Fine Coal Agglomeration) on Magnetic Desulfurization of Dry Pulverized Lower Kittanning Coal, Jefferson County, Pennsylvania via Gravity Feeding Approach: 100-gm Feed Coal, 5-minute Feeding Time[13]

	Case A	Case B	Case C	Case D
1. Particle size, mesh	-60 + 100[a]	-100 + 200[b]	-60 + 100[a]	-100 + 200[b]
2. Field intensity, kOe	10	10	20	20
3. Mags				
weight, gm	5.3	7.4	8.14	9.24
sulfur, wt%	10.54	6.34	11.42	8.43
4. Sulfur removal, %	8.8	3.70	16.05	3.90

[a] Feed coal contains 1-2% moisture, 4.05% total sulfur, 3.73% pyritic sulfur and 18.8% ash.

[b] Feed coal contains 1% moisture, 4.335% total sulfur, 3.354% pyritic sulfur and 13.70% ash.

The second problem which seems to contribute to the reported poor performance of magnetic beneficiation of dry pulverized coal is the limited separator matrix loading capacity in using such packing materials as stainless steel screen, expanded metal, etc. Because of the possible excessive pressure drop, the low viscosity of the carrier gas, etc. in dry separation, the latter packing materials are generally more appropriate compared to stainless steel wool. Unfortunately, the insufficient sharp edges and surface areas associated with these packing materials limit their capabilities for producing large field gradient and for capturing magnetic particles. For example, an approximate indication of such a limited matrix loading capacity in dry separation with stainless steel screens is illustrated in Table VI.

Table VI. Illustration of the Limited Matrix Loading Capacity in Dry Magnetic Separation with Stainless Steel Screens[13]

	Pyrite, -60 + 200 mesh, 24 gm feed, 50 screens, gravity feeding			
1. Field intensity, kOe	0	5	15	20
2. Mags				
weight, gm	3.8	6.3	7.0	8.6
wt%	15.7	26.3	29.3	35.7

For the experiments shown in the table, fifty Frantz screens of 1-in. I.D. and 0.3125-in. thickness constructed from stainless steel strips were stacked together along with forty-nine spacers of 0.1875-in. thickness as separator matrix packing materials. By calculating the active surface area of a screen and by assuming a monolayer particle capture and buildup on both sides of a screen, the maximum amount of spherical pyrite particles which can be collected as mags can be found to be about 8.0 gm for 60-mesh particles, 5.68 gm for 100-mesh particles, and 2.80 gm for 200-mesh particles. These estimated amounts are fairly consistent with those collected experimentally as shown in the table.

Despite the problems of fine coal agglomeration and limited separator matrix loading capacity in dry separation via gravity feeding as as illustrated in the above, two important findings resulted from the recent work with Pennsylvania Lower Kittanning and Upper Freeport coals in the authors' laboratory.[13] First, it was found that the coal feeding rate had essentially no effect on the performance of magnetic beneficiation of dry pulverized coal via gravity feeding. Secondly, under comparable experimental conditions, the sulfur and ash contents of the mags resulted from dry separation via gravity feeding were found to be almost the same as those obtained from wet beneficiation. This point may be illustrated by the approximate comparison between dry and wet magnetic beneficiation of Lower Kittanning coal shown in Table VII.

Table VII. An Approximate Comparison Between Dry and Wet Magnetic Beneficiation of Lower Kittanning Coal, Jefferson County, Pennsylvania[13]

Separation Conditions	Grams		Ash (%)		Sulfur (%)		Pyrite (%)	
	Feed	Mags	Feed	Mags	Feed	Mags	Feed	Mags
1. Dry, gravity feeding, 5 minute feeding time, -100 + 200 mesh, stainless steel screens, 19 kOe	100	9.40	13.07	30.12	4.49	12.96	2.19	10.23
2. Dry, air-entrained fluidization, upward flow, 28.3 cm/sec, stainless steel screens, 19 kOe	100	5.29	14.68	30.60	4.42	12.94	2.59	12.92
3. Wet, 2.5 wt% solids slurry, 2.3 cm/sec, stainless steel wool packing, -200 + 325 mesh, 19 kOe	100	18.02	10.66	29.28	3.93	11.22	2.52	9.11

It can be seen from item nos. 1 and 3 of the table that the weight percents of ash, sulfur and pyrite in the mags resulted from dry separation via gravity feeding and wet beneficiation are of the same order of magnitude, having the ranges of 29.28-30.60, 11.22-12.96, and 9.11-12.92%, respectively. The only difference between dry and wet beneficiation is the amount of mags collected due to their different separator matrix loading capacities. This difference has thus led to the generally poor performance of dry separation via gravity feeding compared to wet beneficiation based on the ash, sulfur and pyrite contents of the separated product coal. Further implications of this difference between dry and wet beneficiation are discussed below along with some results obtained on the magnetic beneficiation of dry pulverized coal in a fluidized-bed separator matrix.

Air-Entrained Fluidization Approach. Prior to the work in the authors' laboratory,[13] there was only one reported study on the magnetic beneficiation of dry pulverized coal via an air-entrained fluidization approach.[10] In that study, a screw or vibratory feeder was used to inject dry pulverized Delmont coal from Westmoreland County, Pennsylvania, into an air stream which would carry it *downward* through the separator matrix of 1-in. I.D. and 6 in. long. The preliminary tests with a screw feeder and an expanded metal matrix showed that the presence of fines in the typically 60-mesh feed coal would make the feeder inoperative; and no significant reduction in the sulfur and ash of the product coal was observed. Subsequent tests conducted using a vibratory feeder with a field intensity up to 50 kOe and air velocities of 59-1019 cm/sec indicated that the weight percent of sulfur removed from the feed coal was very small and irregular, rarely more than 10%. In contrast, experiments carried out with the same pulverized coal in a water slurry showed that HGMS was effective in reducing the total sulfur of the feed coal by 50%, the ash by 50%, and the pyrite by 60-80%. No explanation regarding this significant difference in the performance of dry and wet beneficiation, however, was given in Ref. 10.

An extensive, pilot-scale experimental study of magnetic beneficiation of dry pulverized Pennsylvania Lower Kittanning and Upper Freeport coals via an air-entrained fluidization approach was conducted recently in the authors' laboratory, and the results have been described elsewhere.[13] One major difference of this study compared to that described in Ref. 10 was that an *upward* air-entrained fluidization of the pulverized feed coal through a separator matrix of 5-in. I.D. and 20 in. long was examined. The experiments revealed the same problems of fine coal agglomeration and limited separator matrix loading capacity as observed in dry separation via the gravity feeding approach. Further, it was found that under comparable experimental conditions, the sulfur and ash contents of the mags resulted from air-entrained fluidization were of the same orders of magnitude as those found from dry separation via gravity feeding or wet beneficiation. This point has already been illustrated earlier in Table VII as item no. 2. In addition, the experiments indicated that due to the high velocity of the air stream required to achieve a good entrained fluidization of the pulverized feed coal, the retention time of magnetic particles in coal in the separator matrix was generally very short. As a result, the efficiency of the separator matrix in capturing and retaining magnetic particles in coal was very low. For example, item no. 2 in Table VII shows that for 100 gm of pulverized Lower Kittanning coal entrained in an air stream of velocity 28.3 cm/sec, the amount of mags collected in the separator matrix was only 5.29 gm. The latter was also less than that collected in dry separation via gravity feeding or wet beneficiation as shown in the table.

Recirculating Air-Fluidization Approach. Based on the preceding discussion of experimental results and their implications, it is evident that an effective HGMS process to be developed for the beneficiation of dry pulverized coal in a fluidized-bed separator matrix must include at least two desirable features. Thus, it must have a simple means to reduce the presence of fines in the fluidized coal stream and to avoid their possible agglomeration. It must also provide a sufficient retention time for the fluidized coal stream to promote the contact between the magnetic particles in coal and the active surface areas available on the separator matrix packing materials. The latter is of importance in increasing the capacity of the separator matrix for capturing and retaining magnetic particles in coal. As a result of a joint research program initiated at Auburn University and Oak Ridge National Laboratory on magnetic beneficiation of dry pulverized coal, a recirculating air-fluidization approach possessing the above desirable features has been developed recently; and several novel fluidized-bed separator matrices for use in HGMS applied to dry pulverized coal are currently being tested experimentally.[13] In fact, by using one of the recirculating fluidized-bed separator matrices developed, the performance of magnetic separation of sulfur and ash from dry pulverized Pennsylvania Upper Freeport coal was repeatedly found to be *better than* that from coal/water slurry. This separator matrix was made of three primary sections of increasing inside diameters arranged from the bottom to the top of the matrix. These primary sections are of 5-in. I.D. and 5 in. long (section A), 3.5-in. I.D. and 10 in. long (section B), and 0.75-in. I.D. and 7 in. long (section C), respectively. Connecting sections A and B, and sections B and C are two expanded sections of 3 in. and 4 in. long, respectively. In the experiments conducted with this matrix, packing materials such as stainless steel screens were placed in section B, and the pulverized feed coal placed in an auxiliary fluidized bed outside of the separator was air-fluidized through the separator. By properly controlling the flow velocity of the air stream during the whole separation period, it was possible to collect most of the fines in the pulverized coal stream as top tail product of low sulfur and ash contents. At the same time, because of the unique expanded sections from the bottom to the top of the separator matrix and the resulting gradual decrease in the upward fluidization velocity of the pulverized coal stream, the majority of the pulverized coal particles of medium and large sizes would tend to recirculate inside the expanded sections. As a result, a sufficient retention time inside the separator matrix could be provided to the bulk of the fluidized coal stream without the presence of fines, thus allowing the magnetic particles in coal to be captured and retained by the matrix. Toward the end of the desired separation period, the flow velocity of the air stream was reduced, and the magnetically beneficiated coal of low sulfur and ash content was collected as bottom tail products.

Table VIII shows the typical experimental results obtained with Pennsylvania Upper Freeport coal of particle sizes between 100 and 200 mesh.

Table VIII. Magnetic Beneficiation of Dry Pulverized Upper Feeport Coal, Jefferson County, Pennsylvania via Recirculating Air Fluidization: Air Velocity - 17.7 cm/sec[13]

	Grams	Sulfur (%)	Pyrite (%)	Ash (%)
1. Feed	100.00	2.123	1.519	6.320
2. Mags (20 kOe)				
1-pass	9.05	12.80	11.79	24.87
2-pass	5.99	4.68	4.18	13.26
3-pass	5.12	2.25	1.93	10.00
total	20.20	7.71	7.02	17.65
3. Total tails (20 kOe)	79.80	0.68	0.130	3.45
4. Feed separated as mags	20.20	68.16 [a]	86.80 [a]	52.43 [a]
5. Mags (0 kOe)	5.03	1.35	0.85	4.66

[a] Weight percent of sulfur, pyrite or ash separated from feed as mags.

It can be seen that by using the recirculating air-fluidization approach *and three-pass* separation, HGMS was able to reduce the total sulfur of the Upper Freeport coal by 68.16%, the pyrite by 86.8%, and the ash by

52.43%. Also, the total sulfur content of the tail product was sufficiently low (0.68 wt%) that the magnetically beneficiated Upper Freeport coal could be used immediately as an environmentally acceptable, low sulfur fuel.

The experimental results illustrated in Table VIII have clearly suggested that HGMS with recirculating air-fluidization appears to hold much promise as an effective physical method for cleaning coal. In particular, these results along with those obtained from wet beneficiation described elsewhere[13,15] have shown that the performance of magnetic separation of sulfur and ash from dry pulverized coal via recirculating air-fluidization can be even better than that from coal/water slurry. Obviously, further research and development work related to the quantitative modeling and prediction of separation performance, equipment and process design, etc., in the magnetic beneficiation of dry pulverized is justified.[27]

APPENDIX: BASIS FOR ESTIMATING THE UNIT COSTS OF MAGNETIC BENEFICIATION OF COAL/WATER SLURRY

The detailed operating conditions and estimated unit costs for a typical conceptual process for the magnetic beneficiation of coal/water slurry (case B in Table I) are illustrated as follows.

Operating Conditions

(1) Concentration of coal/water slurry = 25 wt%
(2) Superficial flow velocity = 2.61 cm/sec
(3) Stainless steel wool packing density = 6 wt%
(4) Amount of coal processed per cycle = 7 times weight of stainless steel wool
(5) Amount of washing water required per cycle = 3 times volume of separator matrix
(6) Amount of rinse water required per cycle = 1.5 times volume of separator matrix
(7) Flow velocity of rinse water = flow velocity of coal slurry
(8) Washing time per cycle = 1 min
(9) Time of energizing the magnet per cycle = 0.5 min
(10) Labor required = 2 men per shift
(11) Amount of dispersant = 10 ppm

Investment Costs

(1)	Costs of major installed equipment ($)	
	one HGMS unit	$1,936,000
	pump	38,480
	tank	24,370
		1,998,850
(2)	Add 20% Contingency	399,770
	Total Investment (I $)	$2,398,670

Operating Costs ($ per year)

(1)	Dispersant (57c/lb)	$ 24,120
(2)	Electric power (2¢/KW, 650KW)	102,960

(3)	Water (3¢/1000 gal)	$ 16,440
(4)	Operating labor (2 men/shift X 8304 man-hr/yr X 6.5$/man-hr)	107,960
(5)	Maintenance labor (1.5% of operating investment cost)	35,980
(6)	Supervision (15% of operating and maintenance labor costs)	21,590
(7)	Operating supplied (30% of operating labor costs)	32,390
(8)	Maintenance supplied (1.5% of investment cost)	35,980
(9)	Local taxes and insurance (2.7% of investment cost)	64,760
	Annual Net Operating Cost $\underline{N}$ $	$ 442,180
	Coal Processed Annually $\underline{G}$ tons	528,900

Unit Costs ($ per ton coal processed)

See Ref. 19 and 20 for the cost equations used below.

(1) Based on 0% DCF rate of return:
$\underline{U}_o = (\underline{N} + 0.05\ \underline{I})/\underline{G} = 1.063$ \$/ton

(2) Based on 15% DCF rate of return:
$\underline{U}_{15} = (\underline{N} + 0.34749\ \underline{I})/\underline{G} = 2.412$ \$/ton

(3) Based on capital amortization over 20 years at 10% interest rate:
$\underline{U} = (\underline{N} + 0.11746\ \underline{I})/\underline{G} = 1.369$ \$/ton

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A THEORETICAL APPROACH TO WASHABILITY CURVES IS COMPARED TO THE OTISCA PROCESS SEPARATION OF FINE COAL

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ABSTRACT

An approach to the theoretical washability curve was developed based on the variables of raw coal size distribution, ash and pyritic sulfur concentration. The size distribution of iron pyrite and mineral matter in that coal seam is also required. The analytical treatment was compared to the washability curves developed independently in another laboratory on a pulverized coal sample and on the data developed from the separation of the same coal by the Otisca Process. Although numerous assumptions were required for a complete solution at various gravities, the theoretical curve for pyritic sulfur was positioned about 10 percent higher than the observed washability or Otisca Process data.

INTRODUCTION

Coal preparation technologists have long recognized that their immediate task is to desulfurize and deash coal with a maximum yield of coal product; and this task is complicated by extreme variations in coal seam chemistry and morphology which include the coal itself as well as iron pyrites, mineral matter, and moisture. Furthermore, they also face severe variations in the coal preparation procedure such as the degree and techniques of size reduction, separation specific gravity and procedure, and other significant factors. Some generalities have emerged from this complexity over the years. For example, it is generally recognized that increasing size reduction permits the release of more mineral matter and pyritic sulfur for separation. Verification of this is made evident in numerous reports from U. S. Bureau of Mines(1-4) as is the observation that at a constant size distribution, a reduction in separation specific gravity will produce a coal product also reduced in ash and sulfur. The extreme complexity arising from the presence of these interdependent variables, together with the additional problem that each coal seam is quite different and that there are also variations within one seam of coal from mine to mine, have presented a coal preparation task which is usually solved by experience of the engineer in charge or good old-fashioned intuition.

This approach has served the industry well for many years. However, with the demand for large quantities of cheap coal with an absolute minimum of sulfur and mineral matter we are now faced with the problem of separating these variables in order to achieve the maximum possible reduction of mineral matter. The purpose of this paper is to examine a theoretical approach to the determination of the ultimate limits of ash and pyrite removal from coal, given the specific gravity of separation together with the concentration and size distribution of the raw coal, mineral matter, and pyrite. Some of the experimental data used to test this theoretical analysis were obtained from several other sources and were accumulated for other purposes. As a consequence, the precision suffers. However, it was presumed that with the establishment of this theoretical approach, more accurate experimental data will be developed, leading to an improvement in the correlation. The application of this approach to mineral matter reduction other than pyrite was also developed but could not be tested as the necessary size distribution data were not available.

THE EFFECT OF PARTICLE SPECIFIC GRAVITY

The following analysis is based on the rather straightforward assumption that in the ideal gravity separation of a coal particle from refuse, a very small mineral matter particle buried in the center of a relatively massive coal particle will be recovered as coal product. That is, a theoretical lower limit of retained ash and pyritic sulfur in the coal product is calculated for an ideal separation of the raw coal in an ideal bath. In the simplest case, consider a two-phase system of coal with an unique specific gravity of 1.30 and iron pyrite with a specific gravity of 5.0 where the iron pyrite is embedded in the coal such that the apparent specific gravity of the two-phase particle increases with the volume fraction of pyrite as would the concentration of the pyritic sulfur in the particle. This relationship is important because in an ideal gravity separation of coal and refuse, free pyrite with a specific gravity of five will obviously separate as a reject instantaneously; however, it is now evident that coal product with a

TABLE I

Variation Of Sulfur Concentration In An Ideal Coal-Iron Pyrite System As A Function Of Volume Fraction Of Iron Pyrite

Volume Fraction Iron Pyrite	Combined Specific Gravity	Weight Percent Pyritic Sulfur
0.1	1.67	15.99
0.07	1.559	11.49
0.05	1.485	8.99
0.04	1.448	7.38
0.03	1.411	5.68
0.02	1.374	3.89
0.01	1.337	2.00

substantial amount of pyrite could also be recovered from the separation bath with the coal product at gravities from 1.60 to 1.30. One should observe that there is no regard for particle size in this relationship since only the volume fraction and specific gravity are involved. This relationship will be used later to control the effect of separation bath specific gravity on the concentration of ash or iron pyrite in the coal product. A similar argument can be developed for the three-phase system coal, mineral matter and iron pyrite if we assume an average specific gravity for the coal and the mineral matter.

ANALYTICAL APPROACH

The analysis used in this discussion is based on the assumption that in a given narrow size range of raw coal, if that system were separated in an ideal parting liquid of a particular specific gravity, the coal product floated from the bath will also include some fraction of mineral matter and iron pyrite which was included in the coal particles as a three-phase mixture.

The reason that these high density mineral matter particles were included in the coal product was the fact that they had a particle volume fraction small enough that the apparent specific gravity of the particle was less than that of the separation bath, and that volume fraction of mineral matter was embedded in the coal matrix. The rest of the mineral matter (including iron pyrite) is rejected due to the fact that its specific gravity exceeds that of the separation bath. It should be recognized that this line of argument also implies that a small volume fraction of coal is included in the mineral matter such that the combined specific gravity never becomes less than that of the bath.

Consider, as an example, a raw coal crushed to 1 cm x 0 from a coal seam which had a six inch (15 cm) slate parting. If we examine only that fraction of raw coal in the size range of 1 cm x 0.5 cm, we can assume that all of the mineral matter from the mineral parting not in the interfacial zone in this size range has a specific gravity which exceeds the separation bath specific gravity of, say, 1.50; and thus, will be rejected. In fact, we can also assume that all mineral matter particles larger than that raw coal size range will be rejected. The only recoverable mineral matter will be that which is small enough so that its volume fraction does not cause the specific gravity of the multiphase particle to exceed that of the separation bath. The required information for this solution is the concentration of the raw coal and mineral matter in the given size range and the bath specific gravity, if we can assume an average specific gravity of coal and mineral matter. After examining all size ranges and accumulating the results, we can theoretically ascertain limits of the coal product yield, ash and pyritic sulfur concentration and heat content, if we are provided with the BTU/lb-ash relationship for that particular coal. Furthermore, we can also examine how these functions vary with various methods and limits of raw coal size reduction and separation bath gravity.

RAW COAL SIZE DISTRIBUTION

According to Evans, et al.,(5) coal fractures into a particle size distribution which can be represented by a Rosin-Rammler distribution function of the form

$$R = e^{-b\,(x)^t} \qquad (1)$$

where R is the weight fraction of coal retained on a sieve of opening size (x) in millimeters. The constants b and t are a function of the fracture characteristics of the coal and fracturing technique. For example, different top sizes of raw coal prepared by different comminution techniques result in different slope t and intercept b values for one particular coal when the data are presented on Log-Log R versus Log x coordinates. Mechanically crushed coals usually follow this relationship (linear) for raw coal top sizes well above one inch to sizes well below 0.037 μm (400 mesh). Chemically comminuted coal(6), on the other hand, shows a distinct break in the curve in the range of 595 μm (28 mesh), giving two lines of different slope and intercept. The Rosin-Rammler distribution was accepted as a reasonable representation of the raw coal size distribution in the following analysis.

In order to examine a narrow size range distribution of raw coal, say from 30 mesh to 60 mesh, the weight fraction of the raw coal within this range with a particular set of parameters (b, t) is given by

$$(R_1 - R_2) \qquad (2)$$

where R_1, R_2 are the fractions retained and are given by equation 1.

MINERAL MATTER SIZE DISTRIBUTION

To the author's knowledge, the particle size distribution of mineral matter in raw coal, disregarding iron pyrite, has not as yet been quantified. However, we are all aware that mineral matter occurs in various seams not only as partings 6 to 18 inches (15 to 45 cm) thick and larger, but also in thicknesses in the millimeter range as well as individual sand and/or clay particles in the micrometer and submicrometer size range. Let us presume for the moment that we can describe the particle size distribution of mineral matter in the raw coal seam using a Rosin-Rammler function described above, even though any other suitable function representing that size distribution would also be applicable as long as the key variables were fraction retained (R) on a sieve of opening size (x). The Rosin-Rammler parameters for this mineral matter are taken as R', b', t', and x'. Consider a raw coal sample from this particular seam which is crushed to some top size where the raw coal size distribution is given by R, b, t, and x in equation 1. In a narrow size range, x + dx, the fraction of raw coal in that range is given by $(R_1 - R_2)$ and we can assume that the average particle diameter $(x + \frac{dx}{2})$ also represents an average particle diameter on the mineral matter size distribution curve. All of the mineral matter larger than this average size can be regarded as having been reduced in size by the crushing procedure to reduce the raw coal sample to its size consist; and as such, has the specific gravity of mineral matter, say, 2.2 as an average specific gravity. A fraction of the remainder of the mineral matter, i.e., smaller than the average particle size, will be recovered with the coal product. That fraction is determined by the volume fraction of mineral matter with an average specific gravity of 2.2 which will just cause the coal product to float and be recovered as coal product. All of the mineral matter less than the average particle diameter (x_a) is given by

$$1 - R_a \tag{3}$$

where the fraction with diameters larger than x_a is given by R_a which is defined by b', t', and x_a ($= x + \frac{dx}{2}$). The fraction of two-phase, ash-coal particles which meet the specific gravity requirements is provided by a factor (m); that is, equation 3 becomes

$$1 - \exp\left(-b'(mx_a)^{t'}\right) \tag{4}$$

where m is the ratio of the diameter of the mineral matter particle (d_a) embedded in the coal matrix as a two-phase system to the diameter of the whole system (d_m). The specific gravity of the mineral matter-coal combined particle is given by (G) which is equivalent to the specific gravity of the separation bath. More specifically, the density of the two-phase particle is given by the volume fraction of mineral matter ($\frac{V_a}{V_m}$) times its average specific gravity (ρ_a) plus the volume fraction of coal ($\frac{V_c}{V_m}$) times its average specific gravity (ρ_c) such that

$$V_a \rho_a + \rho_c (V_m - V_a) = G V_m \tag{5}$$

if we assume a two-component system where $V_a + V_c = V_m$ and V_m is the volume of the two-phase particle. Since we are examining the density of any two-phase particle which will separate from the bath if its density is greater than that of the bath and relating this to the apparent diameter of the mineral matter (d_a) and the two-phase particle (d_m) we can then define (m) as

$$m = d_a/d_m = (V_a/V_m)^{1/3} = \left[\frac{G - \rho_c}{\rho_a - \rho_c}\right]^{1/3} \tag{6}$$

where G is the specific gravity of the separation bath. The effect of m on the exponential equation 4 is to cause more mineral matter to report to the rejects as m becomes a smaller fraction, i.e., as the gravity of the bath is increased, increasing m, more mineral matter will report to the product coal as we all recognize from practical experience.

The weight percent concentration of mineral matter (M) in the coal product for any raw coal is then given by

$$M = \sum_{n=0}^{\infty} C_m (R_1 - R_2)(1 - R_a) \tag{7}$$

where the first term C_m is the concentration of mineral matter which is approximately 1.1 times the weight percent ash concentration (dry basis) in the raw coal(3). The second term represents that fraction of raw coal in a particular size range under examination and the third term represents that fraction of mineral matter which can be recovered based on the limitations of specific gravity. The summation is taken over all size ranges of the raw coal size consist such that M represents all of the ash reporting to the coal product as a two-phase system. In achieving this end we have made (inferred) some rather significant assumptions which, in fact, are not necessarily true but may not seriously effect the results. Firstly, one has to assume that the mineral matter is homogeneously distributed which is probably true only for very small sizes, i.e., less than 0.1 mm., but is quite unlikely for particles greater than 1 cm. This suggests that the smallest error will be incurred in the analysis of raw coals with a top size below 0.5 cm. The specific gravity of the pure coal was taken as an unique value which is, of course, untrue due not only to the coal itself, but also due to the mineral matter dispersed therein. The latter problem was accounted for in the analysis of iron pyrite. However, there must be a cross term which is complex due to the large number of exponential terms. In fact, an ultimate analysis should contain each component of mineral matter with its respective size and density accounted for and this is clearly a complex mathematical problem.

IRON PYRITE (PYRITIC SULFUR) SIZE DISTRIBUTION

With the determination of the ideal mineral matter concentration in the coal product, the concentration of the iron pyrite (specific gravity (ρ_p) of five), or the concentration pyritic sulfur (c_p), can be calculated following a similar procedure, recognizing that the specific gravity of coal should be modified to account for the ash content.

The relationship between the iron pyrite concentration, C_{ip}, and that of the pyritic sulfur (C_p) is

$$0.534\ C_{ip} = C_p \qquad (8)$$

and the density of coal with M weight percent mineral matter is given by

$$\rho_k = \frac{\rho_a \rho_c}{\rho_a + 0.01\ M\ (\rho_c - \rho_a)} \qquad (9)$$

where ρ_a is the average density of mineral matter (assumed 2.2) and ρ_c is the average density of coal (assumed 1.30).

Due to the lack of extensive data describing the size distribution of iron pyrite in coal, a distribution function has not been established; however, it was interesting to observe that data recently accumulated could be roughly represented by a Rosin-Rammler plot. Figure 1 shows data points for the observed values(7) of the iron pyrite particles as plotted on Rosin-Rammler coordinates for the upper, middle and

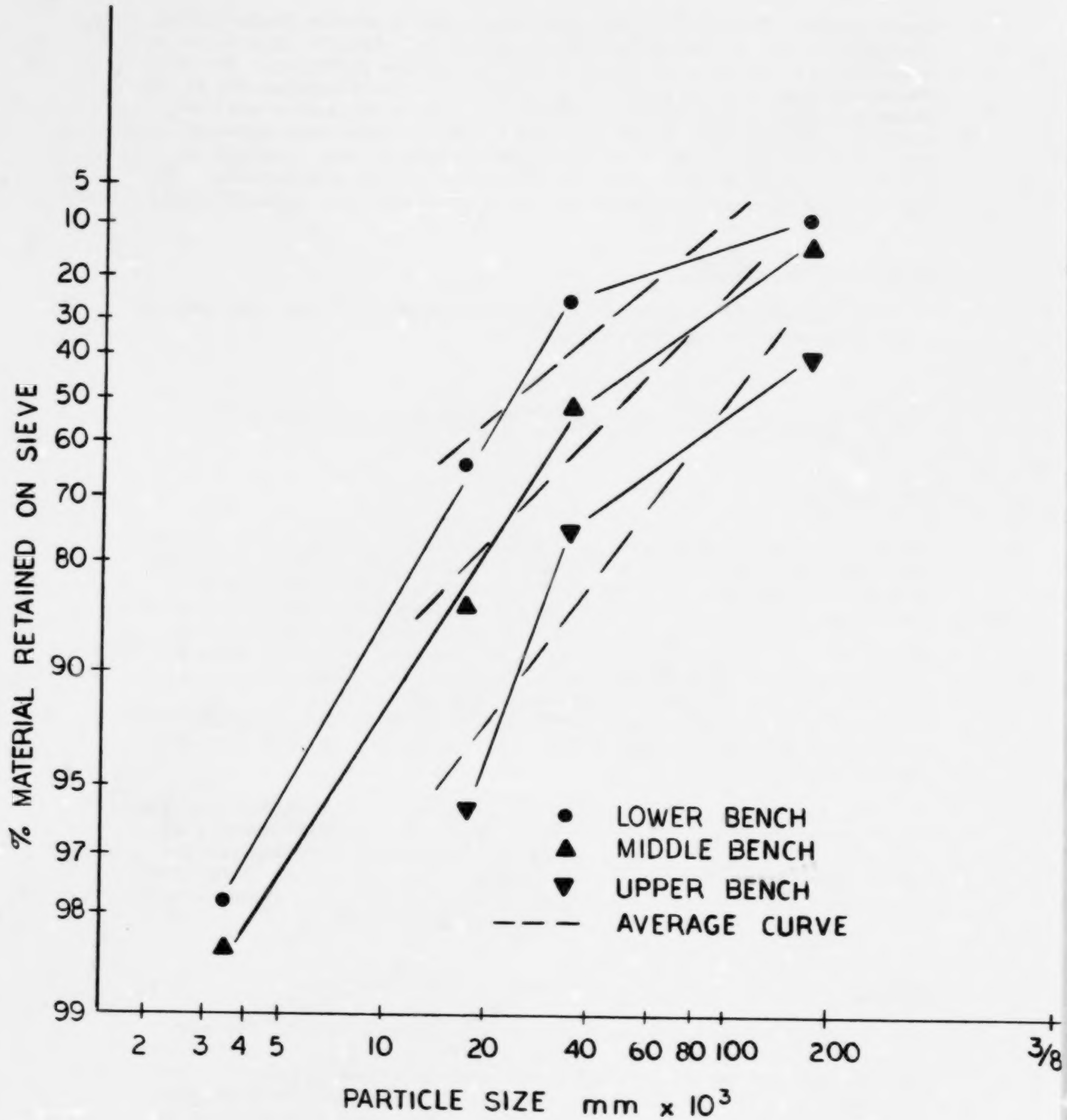

Figure 1. Particle Size Distributions for Iron Pyrite

lower benches of one particular coal seam. For a precise Rosin-Rammler correlation, all of the points should lie on one straight line which is evidently not the case for these particular pyrite particles. The following analysis will incorporate an approximate Rosin-Rammler fit to the observed data for mathematical simplicity. The distribution used here could be replaced with almost any other function which more closely represents the data when it is developed as long as that function involves the variables applicable to the Rosin-Rammler relationship. The error of the approximation used in this case should not be significant.

RETAINED PYRITIC SULFUR

The concentration of pyritic sulfur retained (S_p) in a coal product after separation of raw coal is given by

$$S_p = \sum_{n=o}^{\infty} C_p \left(\exp -b(a2^n)^t - \exp -b(a2^{n+1})^t\right) \left(1 - \exp -b^* \left\{\frac{am}{2}(2^n+2^{n+1})\right\}^{t^*}\right)$$

$n = 0,1,2$

(10)

where C_p is the concentration of pyritic sulfur in the raw coal system; the second term represents the weight fraction retained between successive screen openings, with the size distribution having Rosin-Rammler parameters $\underline{b}$ and $\underline{t}$; and the last term represents that fraction of pyritic sulfur which will be recovered with that coal. The series established by $(a2^n)$ allows a continuous examination of each size range of coal beginning at some minimum value (a) in mm and progressing to the coal top size limit where we must set $(n+1) = \infty$ as there is no coal beyond this size. The term $\frac{a}{2}(2^n+2^{n+1})$ in the third term establishes the average size of the iron pyrite particle in the raw coal size range under investigation.

The iron pyrite size distribution is established with new distribution parameters b^* and t^* and $\underline{m}$ based on the ash modified density of coal (ρ_k). Due to the lack of an exact distribution function for the pyrite under investigation, it was presumed that the dashed lines shown in Figure 1 represented a Rosin-Rammler fit for the data, giving a solution which must be considered only a first approximation.

RESULTS

A raw coal sample pulverized commercially to a nominal 200 mesh (74 μm) x 0 size consist from a coal mine in which the iron pyrite size distribution was recently measured was used to test equation 10. Raw coal samples were carefully separated at different specific gravities by the Otisca Process and also separated at a different laboratory by means of the accepted washability procedures. The complete sulfur form analysis of all of the products of separation and the raw coal were conducted by all parties as a cross-check.

The observed size distribution of the iron pyrite in the three benches of that coal seam were given in Figure 1. In order to simplify the mathematics, each curve was approximated by a straight line, or Rosin-Rammler equivalent, to represent all of the observed data points. The approximation is given by the dashed line in Figure 1. The total pyritic sulfur concentration in the raw coal was about 2 percent (dry basis) which was distributed through the three benches in approximately the following order:

	BENCH		
	Percent Pyritic Sulfur	Mass Fraction	Pyritic Sulfur (C_p)
Top Bench	3.02	0.339	1.022
Mid-Bench	1.81	0.397	0.718
Bottom Bench	1.21	0.264	0.317

Due to different size distributions and concentrations of pyritic sulfur in the three benches, equation 10 was solved for each bench separately and then the data accumulated to ascertain the total pyritic sulfur that would be recovered. The variables necessary for the solution of equation 10 for various separation gravities are shown in Table 2 where it was assumed that the coal retained 8 percent ash as indicated by the washability data. The raw coal size ranges tested, i.e., for $n=o$, $n=1$, $n=2$, etc., when ($a=5\times10^{-3}$mm) were 5 μm-10 μm, 10 μm-20 μm, 20 μm-40 μm, and so on; and there was no coal larger than 0.32 mm.

Identical samples of the pulverized coal sample were separated by an outside laboratory experienced in the standard washability technique and independently on a riffled quarter of that sample of raw coal by the Otisca Process at our laboratory. The products of the Otisca Process separation were then sent to the former laboratory for complete proximate and sulfur forms analysis. The results for the pyritic sulfur in the raw coal cited before and those for the coal products separated at various gravities are shown in Figure 2. A comparison of the results from these two tests for coal product yield, total sulfur and ash are shown in Figures 3 and 4 respectively.

DISCUSSION OF RESULTS

The experimental separation data of the pulverized coal at various gravities shown in Figures 3 and 4 can be considered quite reliable due to the fact that the products and raw coal were analyzed independently by several different groups. The agreement of the theoretical analysis to within 10 percent of the experimental values for the retention of pyritic sulfur in the product coal was considered somewhat fortuitous considering the large number of assumptions that were required to complete the analysis and the fact that the analytical data necessary for the solution of the equations was received by chance rather than by a directed effort. Clearly, the next step is to test this analytical procedure further for other coals and coal seams in order to prove whether or not it is indeed a direction to a theoretical determination of the washability curves.

TABLE 2

SOLUTIONS FOR THE DETERMINATION OF PYRITIC SULFUR RETAINED IN COAL PRODUCT

	BENCH		
	Upper	Mid	Lower
Variables For Equation 10			
b	41	41	41
t	1.30	1.30	1.30
b*	14.2	17.6	11.2
t*	1.33	1.1	0.72
c_p	1.033	0.718	0.317
Solutions For m=0.345 (1.50 Sp.Gr.) a=$5x10^{-3}$)			
n = o	0.0003	0.001	0.003
1	0.002	0.0047	0.0089
2	0.0079	0.0187	0.0259
3	0.026	0.0505	0.0505
4	0.0368	0.0567	0.0412
5	0.0095	0.0112	0.0062
TOTAL	0.0825	0.1428	0.1357
Total Summation 0.361 Percent Pyritic Sulfur Recovery At 1.50 Specific Gravity			
Solutions For m=0.300 (1.45 Sp.Gr.) a=$5x10^{-3}$			
n = o	0.0	0.001	0.002
1	0.001	0.004	0.008
2	0.007	0.016	0.024
3	0.022	0.044	0.047
4	0.031	0.050	0.039
5	0.008	0.011	0.006
TOTAL	0.069	0.126	0.126
Total Summation 0.321 Percent Pyritic Sulfur Recovery At 1.45 Specific Gravity			
Solutions For m=0.239 (1.40 Sp.Gr.) a=$5x10^{-3}$			
n = o	0.0001	0.0006	0.002
1	0.001	0.003	0.007
2	0.005	0.013	0.021
3	0.016	0.035	0.042
4	0.024	0.041	0.035
5	0.006	0.009	0.006
TOTAL	0.052	0.107	0.113
Total Summation 0.272 Percent Pyritic Sulfur Recovery At 1.40 Specific Gravity			

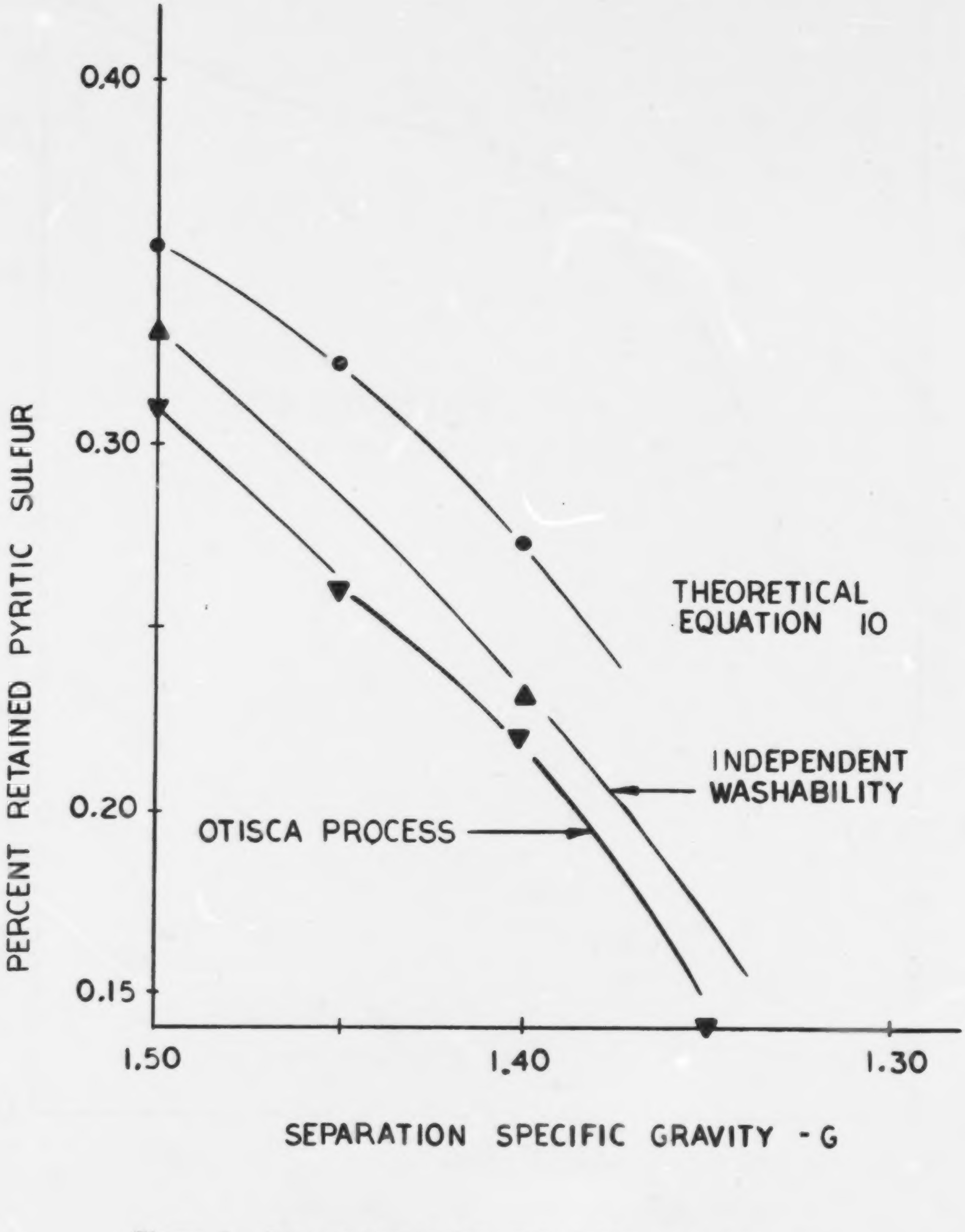

Figure 2. Percent Retained Pyritic Sulfur as a Function of Separation Gravity for 200 Mesh X 0 Coal and Observed Data

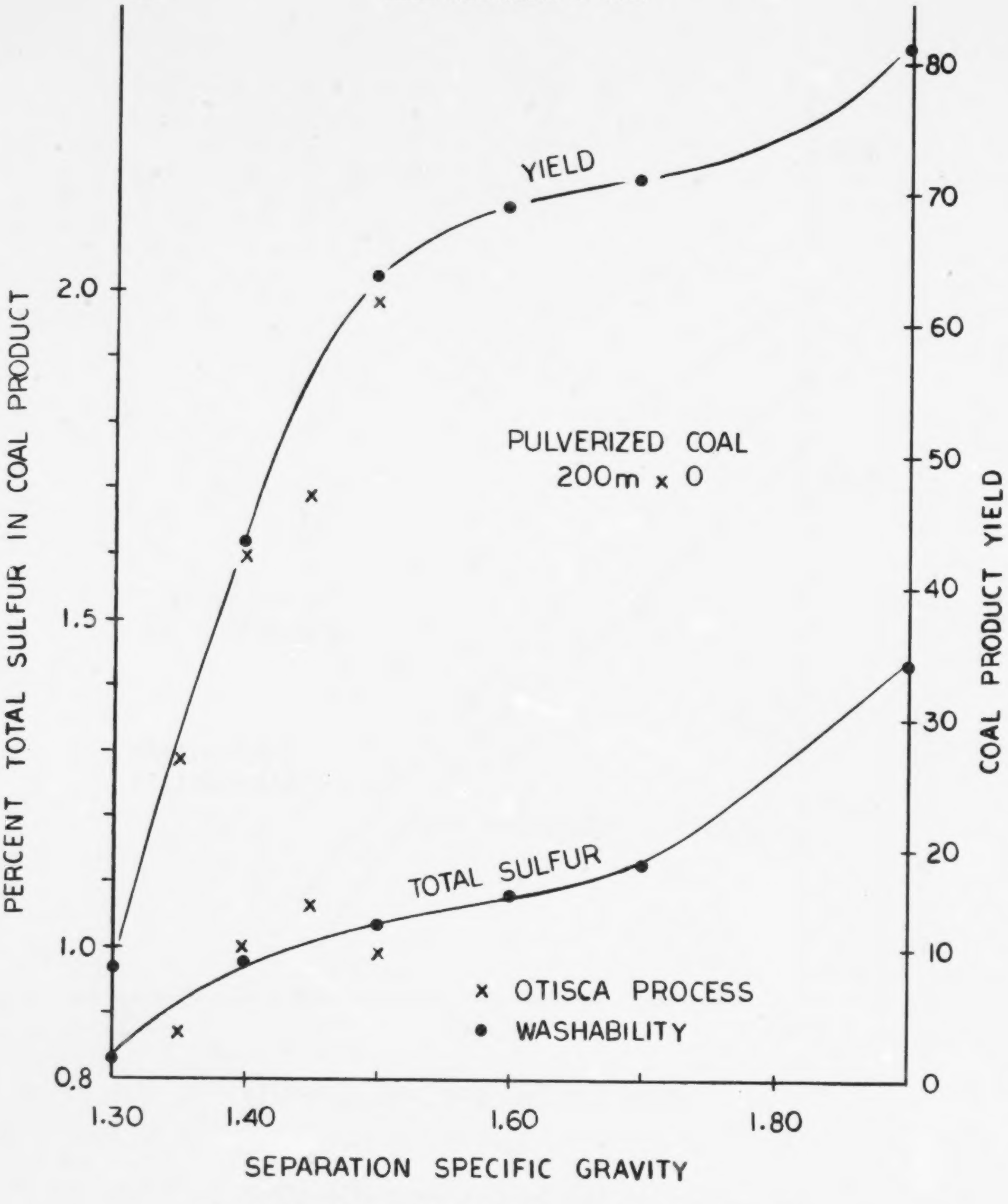

Figure 3. Washability Results for Pulverized Coal

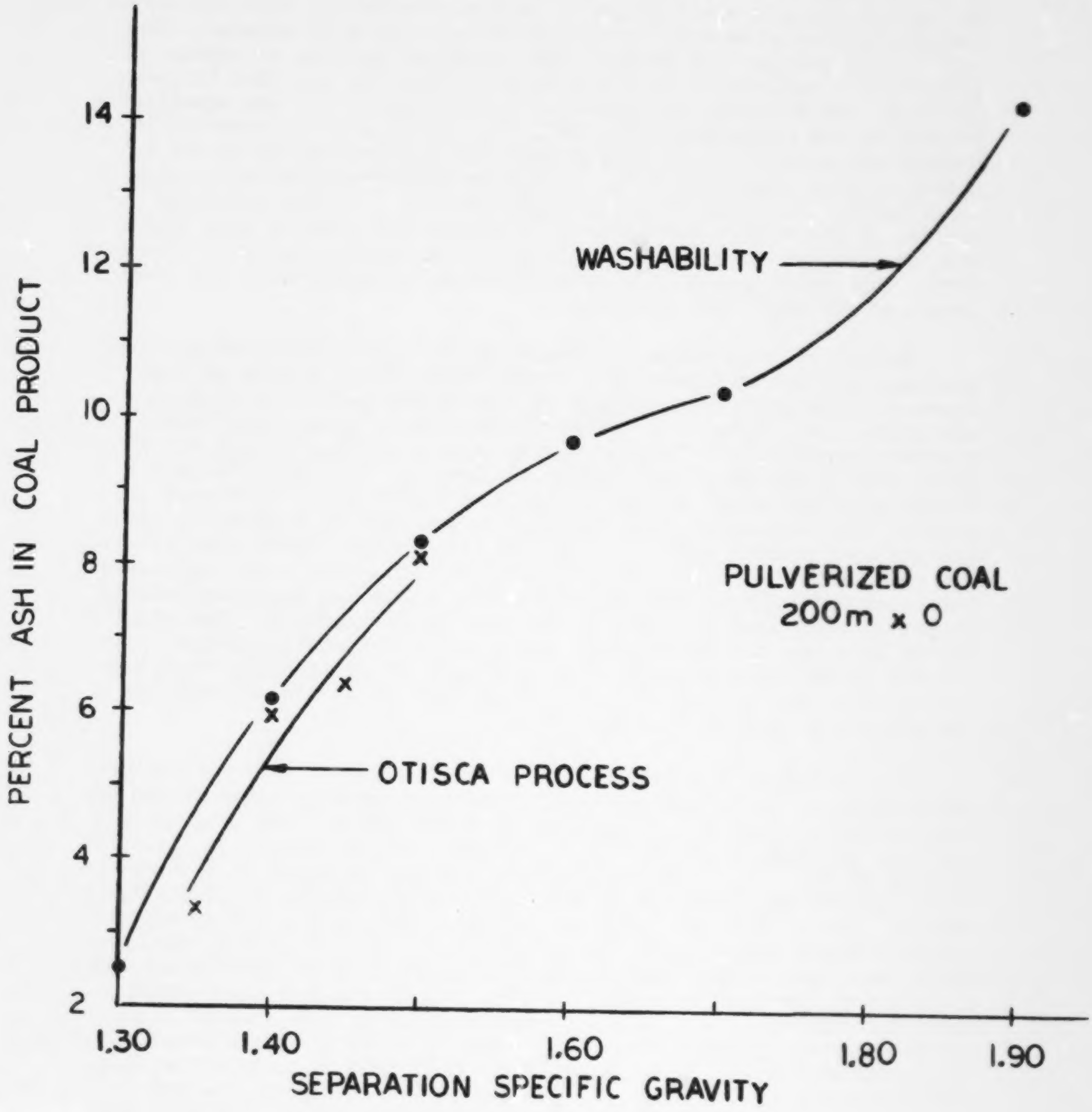

Figure 4. Observed Washability Results for Pulverized Coal

Since there is virtually no mineral matter size distributions available, let us turn immediately to the pyritic sulfur analysis cited. If we assume that current coal preparation techniques have little effect on the organic sulfur in coal and the concentration of sulfate sulfur in eastern coals is small enough to be inconsequential, then the key to desulfurization of eastern coals lies in our ability to eliminate iron pyrite from the raw coal matrix. The variables required to express a quantitative analysis of iron pyrite extraction from raw coal include raw coal size distribution, pyrite size distribution and the specific gravity of the separation bath. Only the pyrite size distribution is outside the control of the coal preparation engineer unless he has a choice of coal seams that have significant differences in pyrite size distribution from which he can extract raw coal. In this case, the choice, if the size distribution is Rosin-Rammler would be that seam with the smallest positive slope (t^*) and the smallest intercept value (b^*). This would present the greatest release of pyrite with the least amount of raw coal size reduction.

Whether or not various techniques of raw coal size reduction, i.e., Hardinge mill versus hammer mill versus other impact methods or even chemical techniques, promote greater iron pyrite release in a given situation, i.e., fixed iron pyrite distribution, has not been demonstrated unequivocally. Quantitatively what is implied is that for a given iron pyrite size distribution, a given raw coal particle size distribution generated by the two different comminution techniques and a given bath separation specific gravity, one form of comminution might produce coal product with less retained iron pyrite. Such might well be the case, if one of our initial assumptions, which was purely arbitrary, was incorrect and that the very small iron pyrite was not homogeneously dispersed throughout the coal system, but lay on preferred sites which during fracture were preferentially freed from the coal particle. Clearly, pyrite embedded within the coal particle will remain there always. Only very careful experimentation with strict control over the variables will provide the final answers.

The analytical expression given in equation 10 is only a first approximation as the effect of certain variables known to exist in the raw coal system have not been considered in their entirety and their effect can only be surmised at this time. Firstly, it was assumed in the utilization of the term (m) which accounted for the variation in bath specific gravity that coal was of only one specific gravity (1.30), and, of course, this is just not true. If, however, this value were an appropriate average specific gravity for all of the coal in that particular seam, one might suspect that the coal of lower specific gravity and its recovery of iron pyrite would just about cancel the lost iron pyrite with the coal fraction of higher specific gravity. The average value of the specific gravity of the coal might be obtained from a standard experimental washability curve which was developed to include the calorific value of that particular coal. After accounting for the BTU units in the pure rejects, i.e., 1.60 gravity or higher, then find that gravity where there are equivalent coal heat units in the rejects and products.

The mathematical simplification of first separating the mineral matter and then the pyritic sulfur neglected the fact that in the real case a three-phase system is involved, i.e., the limiting specific gravity (m) for mineral matter retention should also include the effect of the retained iron pyrite. Although this correction is rather small, i.e., $\rho_k = 1.350$ versus a correct value of $\rho_{k'} = 1.353$, it would tend to depress the theoretical values shown in Figure 2 into the range of the observed data. Most encouraging, however, is the general slope change of the theoretical curve with the variation of specific gravity and its correlation with the experimental curves. That is, the retained pyrite versus specific gravity curve tends towards negative infinity as the separation bath specific gravity approaches the specific gravity of the coal, cf. equation 6.

The development of a washability curve based on the data determined from the above equations is relatively straightforward, that is, the ash in the coal product versus separation specific gravity curve is obtained from solutions for 0.9 M in equation 7, as the $\underline{G}$ value in equation 6 is varied. The total sulfur in the coal product is determined through equation 10 which provides the pyritic sulfur content plus the sulfur contributions due to organic sulfur as most sulfate sulfur is lost in the rejects. Again equation 10 is varied over the entire specific gravity ranges.

Since each of the above calculations represents that fraction of the mineral matter and pyrite recovered in the coal product, the residue of the concentration in the raw coal identifies that quantity of material rejected in the separation and that difference from one represents the coal recovered, i.e., yield, in each separation specific gravity case. A theoretical washability curve has been generated provided our assumptions are not too severe.

The difference between the standard washability curve and the Otisca Process data was due to the different procedures that were used. The standard washability tests used a standard commercial solvent system with a separation time of about twenty-four hours. The Otisca Process used a proprietary liquid and an additive package which allowed a separation time of not more than twenty minutes for size consists of less than 100 mesh (0.1 mm) x 0. Figures 3 and 4 represent the first head-on tests using the Otisca Process and standard washability on a common sample. The results were rather encouraging.

CONCLUSIONS

A first approximation for the theoretical determination of washability curves was presented and partially tested using a nominal 200 mesh x 0 raw coal separated by classical washability techniques and the Otisca Process. The results indicated that the pyritic sulfur retained in the product coal could be determined within 10 percent for raw coal separations in an ideal bath at specific gravities of 1.50, 1.45, and 1.40. The key variables required for this analysis include for the raw coal the size distribution of the iron pyrite, mineral matter, and the crushed raw coal and the concentration of the ash and iron pyrite. The specific gravity of the coal, mineral matter, iron pyrite, and separation bath are also required. One of the key utilizations of this analytical approach is that for a given seam, i.e., fixed mineral matter and iron pyrite size distribution, the optimum comminution schedule can be determined to permit the maximum reduction of ash and pyritic sulfur in the product coal. Furthermore, once the theoretical limits for this seam are available, then one has a fixed reference point for comparison with practical coal preparation procedures.

ACKNOWLEDGMENT

The author would like to acknowledge the valuable comments and insights provided by Dr. Andrew Rainis during his review of this paper.

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SESSION III - COMBUSTION TECHNOLOGY

SESSION CHAIRMAN: G. BLAIR MARTIN, U.S. EPA

In achieving the projected increased use of coal in the industrial and utility sectors, a major emphasis must be placed on the environmental impacts of the combustion systems. The pollutant species to be considered include not only the criteria pollutants (SO_x, NO_x, CO and particulate) but also trace species (POM, organics and trace metals). To control emissions in the most energy-efficient and cost-effective manner, the combustion system should be considered from an overall point of view and may include provisions for precleaning of the fuel, proper design of the combustion device and postcleaning of the flue gas. The combustor design is determined by the choice of process for control of SO_x emissions. The sulfur may be removed from the fuel (coal cleaning or gasification), removed during the fuel combustion process (fluid bed combustion), or scrubbed from the flue gas (pulverized coal boiler).

Coal cleaning and flue gas treatment are covered in other sections of the report; therefore, this session concentrates on the combustion processes or equipment that may be used in conjunction with the various SO_x and particulate removal schemes. The pollutants that may be controlled by proper design of the combustion process include NO_x, CO, POM, organics and carbon particulate. Modification of the combustion process has significant potential for NO_x control while maintaining low levels of the other pollutants. Since the currently available technology is the conventional pulverized or stoker coal-fired boiler with low sulfur fuel or flue gas desulfurization, emphasis is placed on this type of equipment. Some potential near-term technologies are also being developed and two of these are also represented.

The overall session is split up into three types of papers. There are two papers covering general aspects of combustion technology: (1) the basic design and operating principles of combustion systems, and (2) the basic aspects of pollutant formation and control in the fuel combustion process. There are three papers dealing with current technologies for combustion of coal: (1) low emission burner design for pulverized coal-fired utility boilers, (2) coal oil mixture combustion in industrial and utility boilers, and (3) stoker coal-fired industrial boilers. Finally, there are two presentations on potential near-term alternatives: (1) fluid bed combustion of coal for industrial steam generation, and (2) pulverized coal burners for industrial process furnaces.

SOME CHARACTERISTICS OF COAL COMBUSTION SYSTEMS

by

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INTRODUCTION

Coal is burned in a large number of industrial processes: in furnaces, kilns and boilers. The recent development of coal combustion systems is, however, closely tied to the development of steam raising plants. Stoker firing has reached a high level of sophistication but could not follow the steady increases in unit capacity demanded by the economy of scale in power station development and gave way to pulverized coal combustion which in its various forms is the presently prevailing mode of industrial coal combustion. As a result of environmental concerns and also due to the plans for significant expansion in the use of coal, interest turned toward a new combustion system, the fluidized combustion of coal, which holds out promise for sulphur retention without flue gas desulfurization, and low NO_x emission at low capital and operating costs. The scope of this paper does not permit detailed discussion of these processes; it is intended instead to draw attention to some characteristics of these combustion systems, seen through the physical-chemical processes that coal undergoes during combustion.

In coal combustion processes the engineering task is to insure

- stable ignition of the coal
- complete combustion of both the volatiles and the residue of char
- low pollutant emission
- good availability of plant (free of excessive deposit formation and corrosion)
- all these achieved with a minimum of excess air at an acceptable cost in pressure energy.

It is of special advantage if a combustion system can be easily integrated into energy conversion cycles of high thermodynamic efficiency. In the following we shall look at combustion systems from the point of view of how far they satisfy the above criteria.

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PYROLYSIS, IGNITION AND COMBUSTION OF COAL

When coal is heated, the moisture is expelled first, followed by the thermal decomposition of the coal. This latter process is usually called devolatilization. The amount of the volatile matter driven off depends upon the type of coal and also upon the rate of heating and the final temperature of pyrolysis. The higher the final temperature and the rate at which the coal is heated, the larger the proportion of the mass lost during devolatilization. At sufficiently high temperature the total solid combustible mass of the coal can be volatilized. The process of volatile evolution can be quantitatively described in terms of a large number of simultaneous irreversible, first-order reactions[1].

Ignition usually occurs during the thermal decomposition of the coal. It is likely that some of the lower ignition-temperature high molecular weight hydrocarbons ignite first. Their ignition may be catalyzed by the solid surface which may also be ignited during this process[2]. In large particles, where the volatile evolution and burning goes on concurrently with the combustion of the solid matter, it is difficult to separate these processes in time. (This is reflected in the need to provide sufficient space for volatile-combustion in stoker-fired combustors almost above the whole length of the grate.)

The combustion process of the residual char can be considered to consist of steps such as (a) the diffusion of the oxidant to the particle surface in counter-diffusion with the products of combustion away from the surface, (b) the diffusion into the pores of the particle, and (c) the chemisorption reaction at the surface, consisting of the activated adsorption of the oxidant and the desorption of the compounds formed at the surface. The relevance of these individual steps to the overall rate of burning of the particle depends upon parameters such as particle size and reactivity of the char, temperature, and the nature of the oxidant (CO_2, H_2O, OH or O_2). For example, when the particles are large and the temperature is high (stoker firing), the rate determining step is external diffusion; when the particles are large and the temperature is low, diffusion and/or chemical reaction can be the rate limiting steps (fluidized combustion); and when the particles are small and the temperature is high (pulverized coal combustion), diffusion and/or chemical reaction at the surface determine the overall rate of the oxidation reaction[3].

STOKER FIRING

Ignition on the Traveling Grate

The top layer of coal on the grate is heated by radiation from the flame, and by convection from hot combustion products. The combustion air preheat temperature is usually low (<200°C) in order that the air can cool the grate. When coal is ignited from below by air preheated to higher temperatures, high relative velocities between coal and gas will reduce ignition delay. Figure 1 illustrates how ignition delay-times depend upon the air velocity for the case of ignition from the top by radiation and/or from below by air preheated to 425°C; it can be seen that there is an "ignition gap" in the range of gas velocities of 0.11-0.27 Nm/s in which neither of the above-mentioned ignition modes can produce ignition by themselves. Ignition can, however, be obtained by the combination of the two methods[4].

Figure 2 represents an optimized form of the refractory arches determined by modeling radiative transfer between the burning coal on the grate and a refractory arch on one hand, and between this refractory arch and the green coal on the other[5]. Care had to be taken to ensure that the ignition arches serve their purpose without causing slagging at the high temperature end of the grate.

Another engineering solution to improve the ignition of a high moisture coal is shown in Figure 3[6]. The lower part of the coal hopper is altered to enable hot combustion products to be drawn through the coal layer before it reaches the grate. In this arrangement only the fixed grate, at the bottom of the hopper, has to stand up to high gas temperatures and the beneficial effect of combined ignition can be obtained without the flow of highly preheated air through the traveling grate.

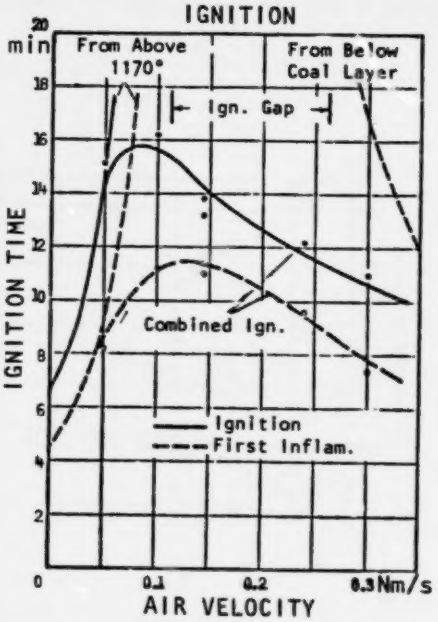


Fig. 1. Ignition by Radiation from the Top and by Convection From Below the Grate (After Gumz[4]).

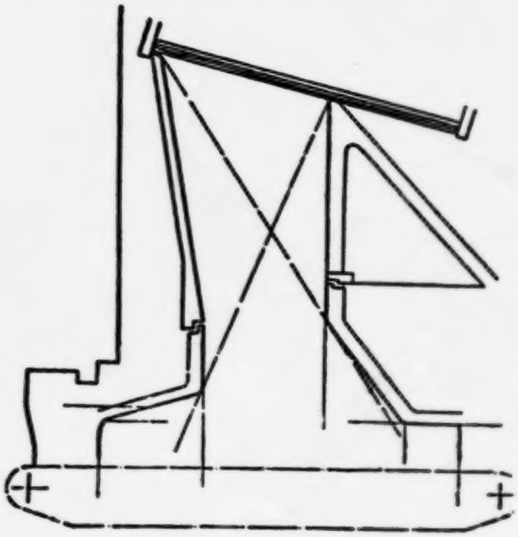


Fig. 2. Ignition Arches in a Travelling Grate Stoker.

Combustion on the Grate

Combustion in carbon channels has been studied as a representative system of combustion in a fixed bed. In practical fuel beds the channels are tortuous, variable in cross section and their walls are uneven. Although the single straight carbon channel is a strongly idealized system, theoretical and experimental studies yielded valuable information relevant to the combustion mechanism of fixed beds. In Figure 4 the variation of combustion rates of a carbon channel with air velocity is shown for three temperatures[7]. While the combustion rates can be seen to level off at low air velocities (laminar flow), they are increasing again, once the flow becomes turbulent at higher air velocities. Another significant finding of these researchers is that the composition of the combustion products shifts toward higher CO/CO_2 ratios as the blast velocity increases. This has been confirmed to hold also for a fixed bed of particles[8] as shown in Figure 5.

On the traveling grate steady state conditions prevail: the events that happen sequentially on the fixed grate can be seen spatially separated, but occurring concurrently on the traveling grate. Figure 6 illustrates this point: the composition of gaseous species above a traveling grate are shown on the top, and their respective volume flow rates through the burning layer of coal, on the lower part of Figure 6[9].

The operation of practical fuel beds is hampered by nonuniform pressure drop across the bed due mainly to the nonuniform distribution of the fine particles on the grate. Fine particles tend to segregate during their passage through storage bunkers and in the hopper above the grate and will cover the grate in patches.

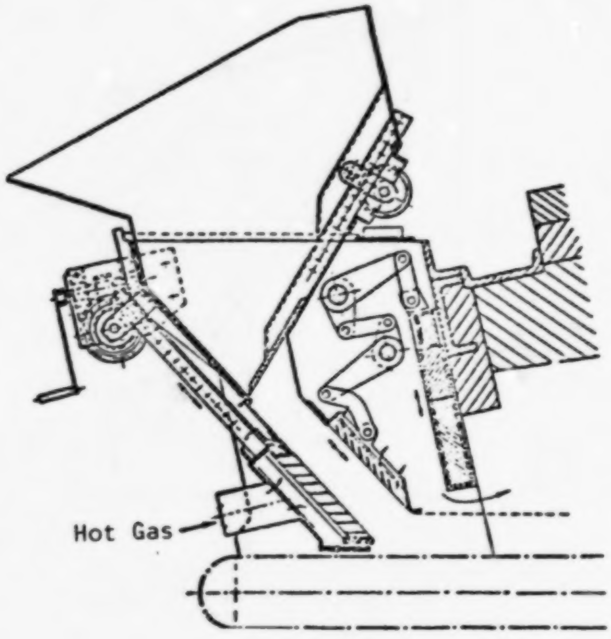


Fig. 3. Ignition by Hot Recirculated Gas.

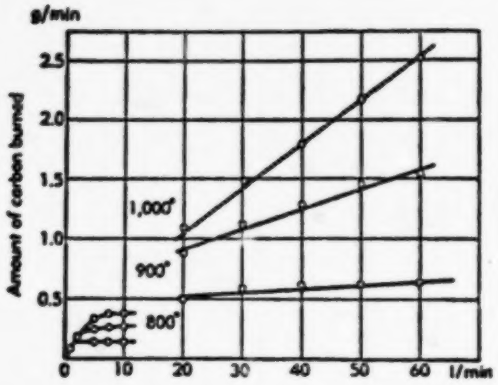


Fig. 4. Variation of Combustion Rate of a Carbon Channel with Air Velocity (After Tsukhanova[7]).

Figure 7 represents results of experimental studies[10] showing the effect of the proportion of fines (<5mm) in the feed upon boiler performance and efficiency.

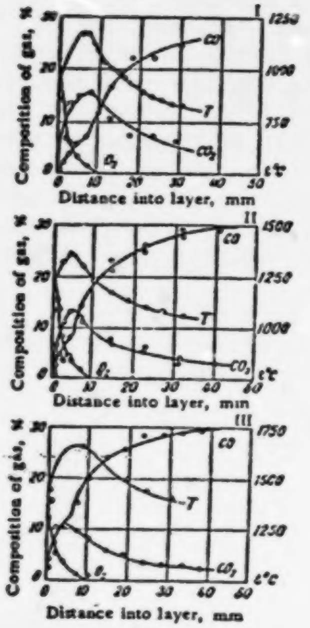


Fig. 5. Gas Formation in a Layer of Particles of Electrode Carbon: I) Rate of Blast 0.11 m/sec; II) Rate of Blast 0.49 m/sec; III) Rate of Blast 1.50 m/sec (After Khitrin[8]).

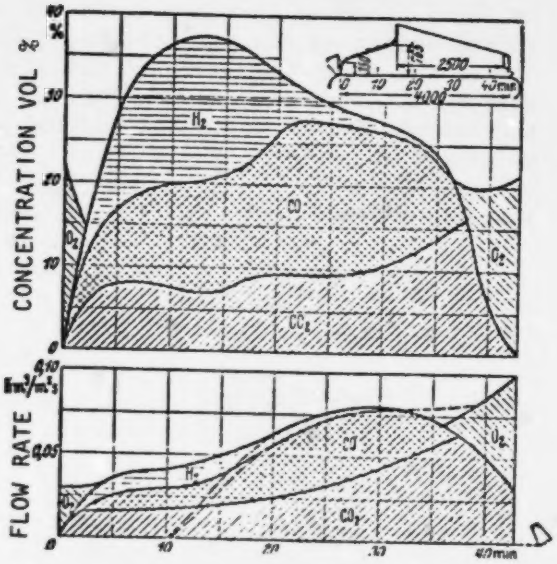


Fig. 6. Species Concentration and Flow Rate Distribution Above a Travelling Grate (After Werkmeister[9]).

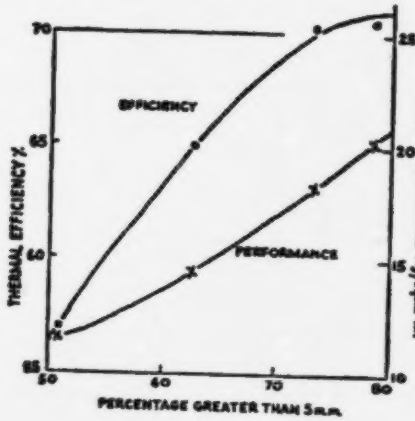


Fig. 7. Effect on Efficiency and Performance of Removing Fines from a Fuel Bed (After Zagon in Ref. 6).

One of the engineering solutions of this problem was the development of spreader stokers (Figure 8): the coal, unclassified, is thrown or blown into the combustion chamber and due to the inertial and drag forces acting on the particles in flight, the smaller particles land on top of the large particles on the grate. The finest particles burn in suspension above the grate. This in turn makes it necessary to raise the height of the combustion chamber and then to cool walls by screens of steam generating tubes to avoid slagging of the refractory surfaces by the fly-ash. Because of the high dust loading of the flue gas, spreader stokers normally require mechanical particle precipitators.

Another solution of the problem caused by fine particles, a combination of coal classification, stoker and pulverized coal combustion is shown schematically in Figure 9[11]. The coal is fed into a flash

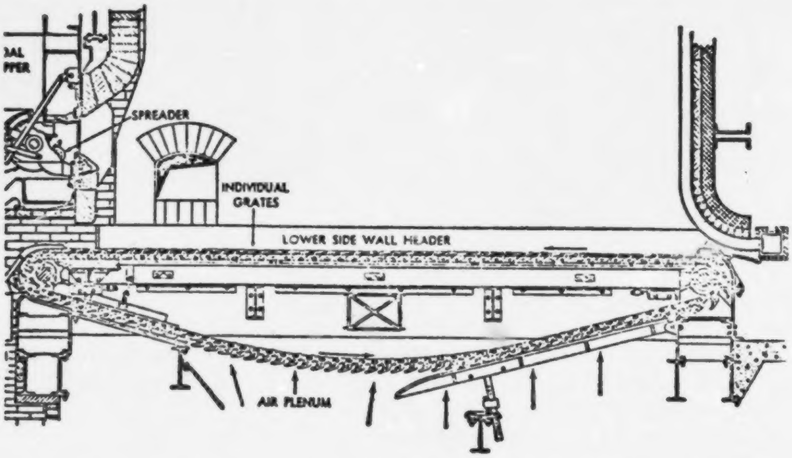
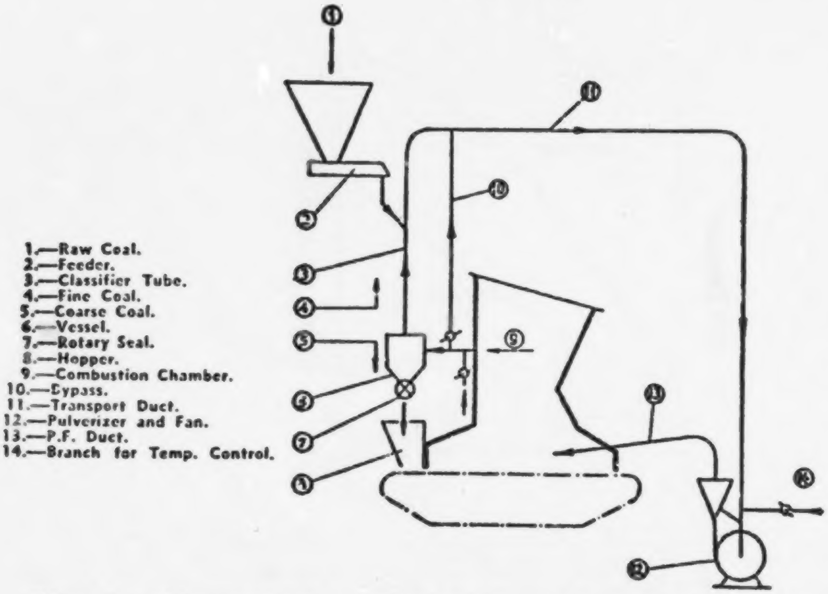

AL
PPER
SPREADER
INDIVIDUAL
GRATES
LOWER SIDE WALL HEADER
AIR PLENUM

Fig. 8. Traveling Grate Stoker. Section Through Rotograte Stoker Installation.


1.—Raw Coal.
2.—Feeder.
3.—Classifier Tube.
4.—Fine Coal.
5.—Coarse Coal.
6.—Vessel.
7.—Rotary Seal.
8.—Hopper.
9.—Combustion Chamber.
10.—Bypass.
11.—Transport Duct.
12.—Pulverizer and Fan.
13.—P.F. Duct.
14.—Branch for Temp. Control.
①
②
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⑭

Fig. 9. Diagrammatic Arrangement of the Combined Firing System. (Beér[11])

drier tube and drops in counter-flow with hot combustion products drawn from the combustion chamber. The fines are lifted from the surface of large particles, carried by the gas stream into a pulverizer, and blown through burners into the combustion chamber above the grate. Due to the interaction of the combustion of classified coal on the grate and the pulverized coal flame above the grate, high combustion efficiencies with low excess air can be obtained even when burning low grade coal. When existing stoker-fired boilers are fitted with this system, the boiler performance can also be significantly raised[11].

PULVERIZED COAL COMBUSTION

As the unit capacity of boilers rose significantly, during the period between the two World Wars, and there was a requirement for improved efficiency and better automatic control, pulverized combustion of coal has steadily replaced stoker firing in units larger than 250,000 lb/hr steam, and therefore in utility application almost entirely.

The combustion efficiency in pulverized coal combustion is high because particles dried and ground to below 200 μm can be intimately mixed with the combustion air, and burned completely with a minimum of excess air. The combustion air can be preheated to high temperatures unlike in stokers where the combustion air has to cool the grate. The use of higher air-preheat means that the flue gas leaving the boiler can be cooled by the much larger air preheater and hence advantage can be taken of regenerative feed water preheat with steam bled from the turbine without any deterioration in boiler efficiency.

Due to the relatively short residence time of the burning coal in the combustion chamber (<2 sec) load-following is only limited by the rate at which the coal grinding-feeding system can respond to command. This varies with different coal preparation systems but the response is generally fast, the time constant being about one minute. The fast response characteristics are compatible with requirements for flexible automatic control and good load following of the boiler plant.

Last but not least, the nature of the flame: capable of filling the combustion chamber with a strongly and uniformly radiating medium made it possible to adapt to this combustion system the water walled, "radiant" combustion chamber design, and this has ensured the scaling up of pulverized coal combustion to the sizes of the largest utility units (>1000 MWe).

Ignition of Pulverized Coal

When a cloud of pulverized coal particles is injected into a furnace, it is heated up as it approaches the flame front partly by radiation and partly by mixing with hot recirculated combustion products.

Nusselt[12] in a classifical paper developed the theory of unidimensional laminar flame propagation in a coal dust cloud and solved his equations for the flame speed as a function of particle size, dust loading of the gas and temperature of the flame, assuming solely radiative heat transfer. Essenhigh and Csaba[13] have used Nusselt's theory for the interpretation of Csaba's experiments. Figure 10 shows results calculated from their study for "ignition temperatures" of 650°K and 900°K, respectively. The prediction is that particles of 30 μm diameter will have ignition delays of about 100 ms and flame speeds lower than 1 m/s for the above ignition temperatures of the dust cloud and assuming a maximum radiance of the flame at 100 kcal/m^2sec.

Rates of flame propagation in practical pulverized coal flames are, however, about an order of magnitude higher than those shown in Figure 10, due mainly to the effect of hot gas entrainment into the fuel-jet as it approaches the flame front (Figure 13a)[14]. The respective contributions of radiation and hot gas entrainment to the ignition of a pulverized anthracite as a function of distance from the burner and for different coal finenesses are shown in Figure 12, and ignition distances for the same anthracites and for two burner types in Figure 11[15].

The heat required for raising the combustion air temperature to ignition is several times that necessary for heating up the coal particles in the coal-air mixture. This is one of the reasons for injecting the coal dust with only a fraction of the total combustion air, the so-called primary air. The rest of the combustion air is normally mixed in downstream of the flame front.

The primary air fraction is usually proportional to the volatile matter of the coal so that sufficient air is available for the combustion of the volatiles as they evolve. Figure 13a and b show the effects of the primary air fraction and the volatile and ash content of the coal upon the flame propagation rate.

Results of Badzioch's experiments on isothermal decomposition of coal[16] are shown in Figure 14. The family of curves illustrates the point that volatile yield is a strong function of pyrolysis temperature.

In recent studies carried out by Anthony and Howard[17] and by Kobayashi, et al.,[18] it was shown that an increasing proportion of the combustible solid mass can be volatilized as the pyrolysis temperature increases and that the volatile yield so produced can far exceed the volatile matter determined by ASTM standard test (Figure 15). In staged combustion processes it will be of advantage to volatilize a large proportion of the coal and thus provide conditions for the conversion of the maximum amounts of fuel-nitrogen to N_2 in the first, fuel-rich stage of the process[19,20].

The solid residue burns out in the second stage or the tail-end of the flame. The combustion of "large" particles (>100 μm) is normally controlled by external diffusion and hence their burning times are proportional to the square of the initial particle diameter[4] (Figure 16). For smaller particles the burning time becomes longer than that predicted from diffusional transport because the rate determining step in their reaction mechanism is the activated adsorption of the oxidant on active sites at the surface or in the pores of the solid. Since the rate of mass transfer varies inversely with particle diameter and the rate of chemical reaction is independent of particle size, the temperature at which the transition from mass transfer to chemical rate control occurs must depend on the particle size. The nature of this dependence is

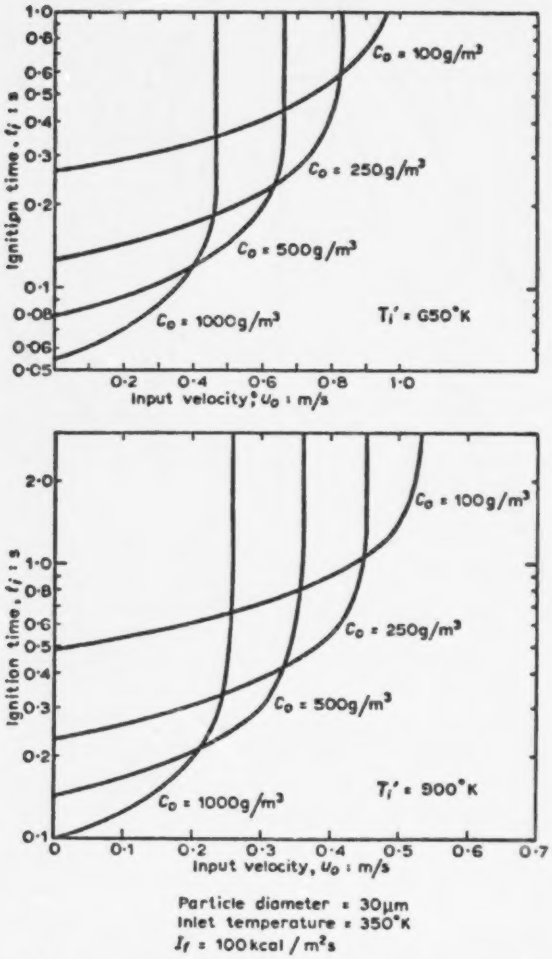


Fig. 10. Theoretical Variation of Ignition Time with Input Velocity, Coal Concentration and Ignition Temperature in Plug Flow.

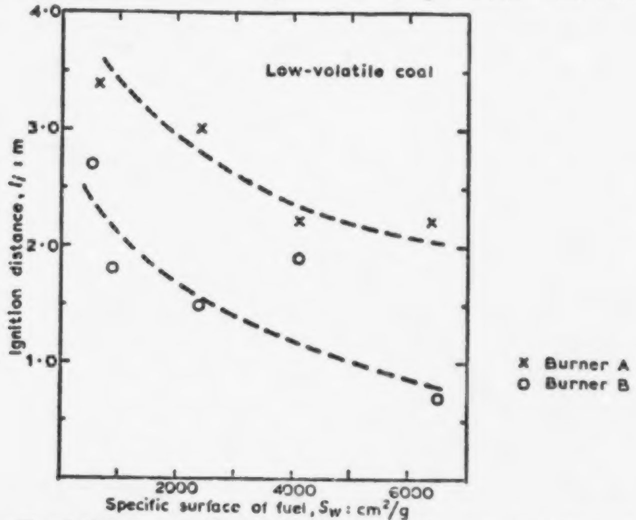


Fig. 11. The Variation of Ignition Distance in Anthracite Flames as a Function of Fineness[15].

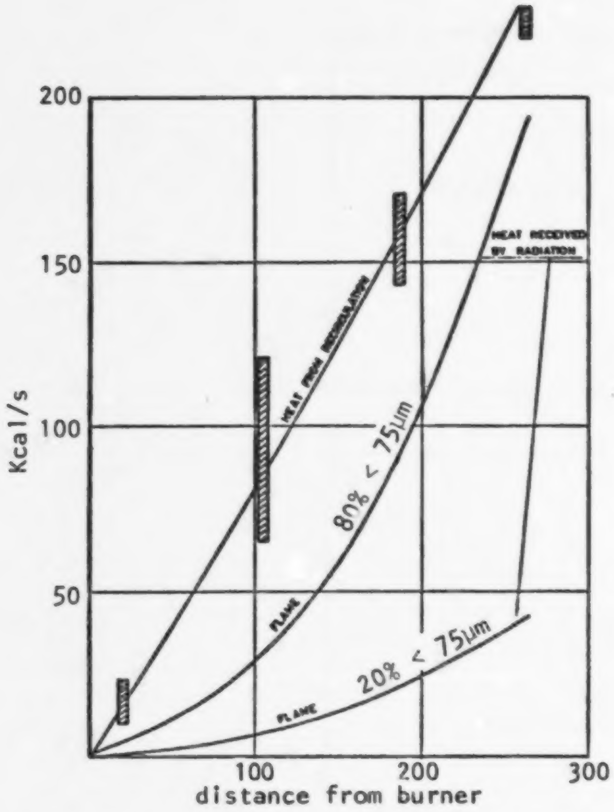


Fig. 12. Heat Transferred to the Pulverized-Fuel Jet Upstream the Flame Front by Recirculation and Radiation.

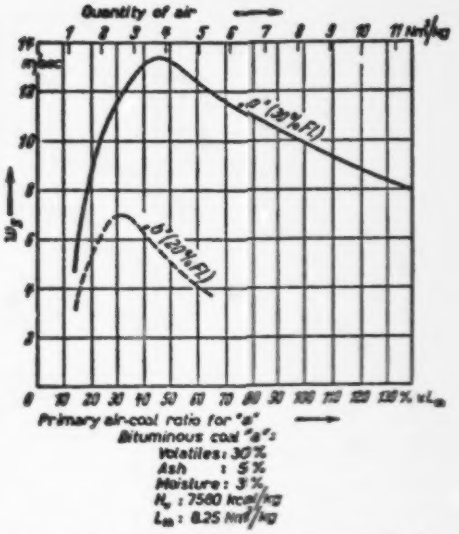


Fig. 13a. Relation Between Primary-Air Fraction and Ignition Velocity of Pulverised-Coal Mixture.

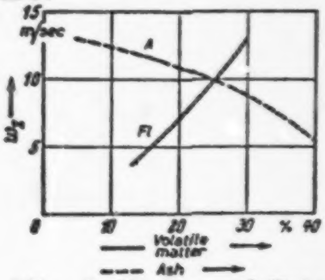


Fig. 13b. Influence of Volatile Matter Content and Ash Content on Ignition Velocity of Pulverised-Coal Mixture (After Dolezal[14]).

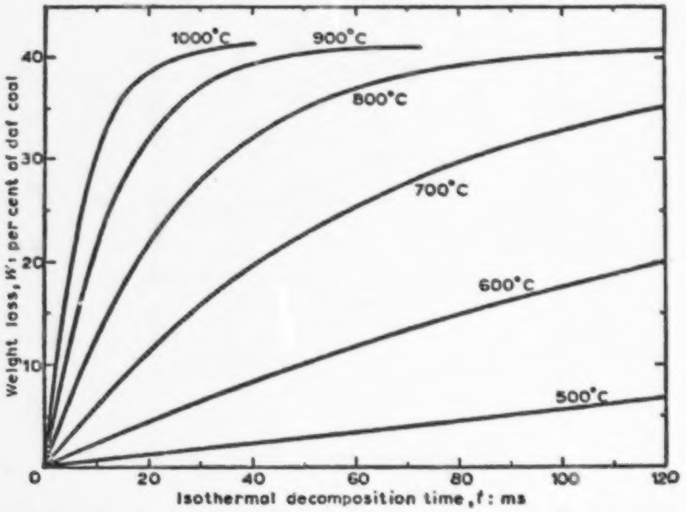


Fig. 14. Variation of Weight Loss with Time at Various Temperatures For a Coal of Low Rank (After Badzioch[16]).

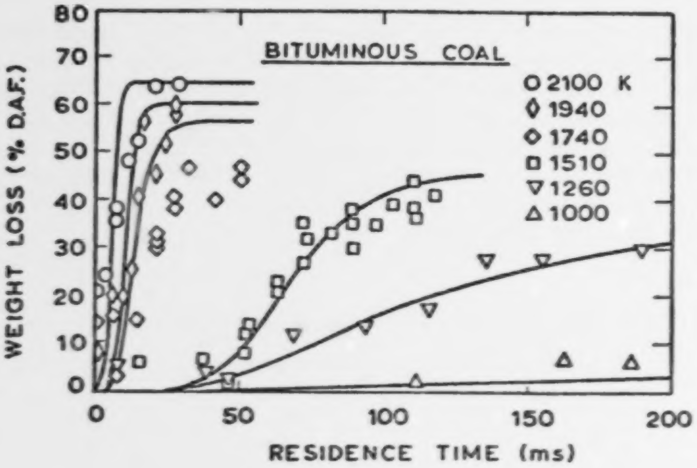


Figure 15.
(After Kobayashi-Howard and Sarofim[18]).

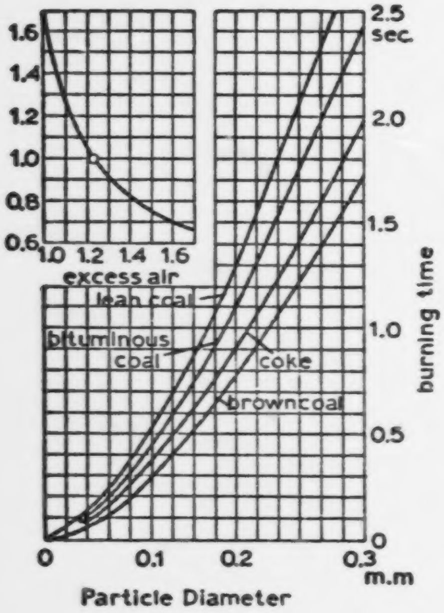
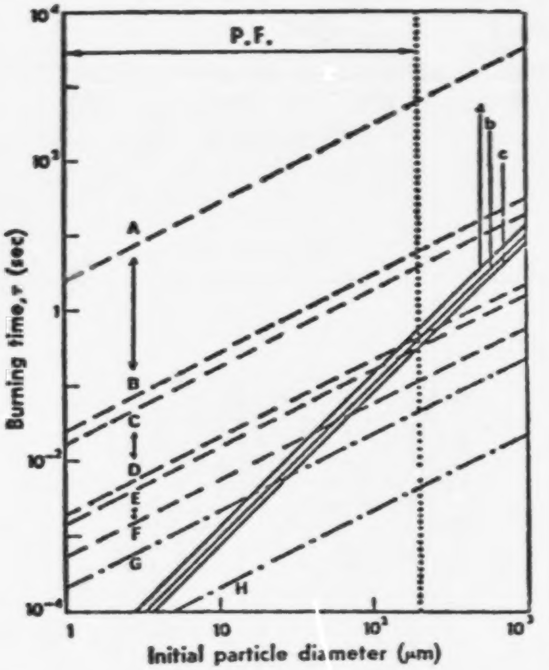


Fig. 16. Burning times of Coal Particles.
(After Gumz[4]).

illustrated by the logarithmic plot of burning time against particle diameter given in Figure 17[21]. It follows that the rate of burning of small particles (<50 μm) depends more on the temperature and the partial pressure of the oxygen, than on the particle size.

In practice there are many methods for aiding ignition or combustion of difficult-to-burn coals. The environmental constraints of low NO_x emission, however, make their application more difficult. Two such methods are mentioned in the following with examples of application to low grade coal combustion in power station boilers: (a) improving ignition and combustion by means of changes in the coal preparation system, and (b) the use of pulverized coal pilot flames to ensure stable ignition when burning low grade coals.



	T (°K)	E (kcal mole⁻¹)	P (atm.)
A	1000	20	1
B	2000	20	1
C	1000	10	1
D	2000	10	1
E	1000	5	1
F	2000	5	1
G	2000	10	10
H	2000	10	100

Solid lines indicate mass transfer control, all pressures; a, 1000°K; b, 1600°K; c, 2000°K

Fig. 17. Theoretical Particle Burning Times Showing Effects of Particle Diameter, Temperature and Pressure. (Ref. 21)

Unlike in other coal burning systems, in pulverized coal combustion the coal preparation (drying, grinding, transport of fuel to the burners) is an integral part of the combustion system. The coal preparation can be "direct" or "bin and feeder." Direct coal preparation (Figures 18a, b) means that the drying medium--preheated air and/or flue gas--is moving the fuel through the grinding mill, and the particle size classifier, transports the ground coal to the burners and serves also to provide the immediate environment for the coal during pyrolysis, ignition and the initial stages of burning. Direct coal preparation plants are relatively simple, but the task to satisfy the many, often conflicting requirements for drying, classification, transport and primary air during ignition and combustion is difficult, particularly for low grade coals[22].

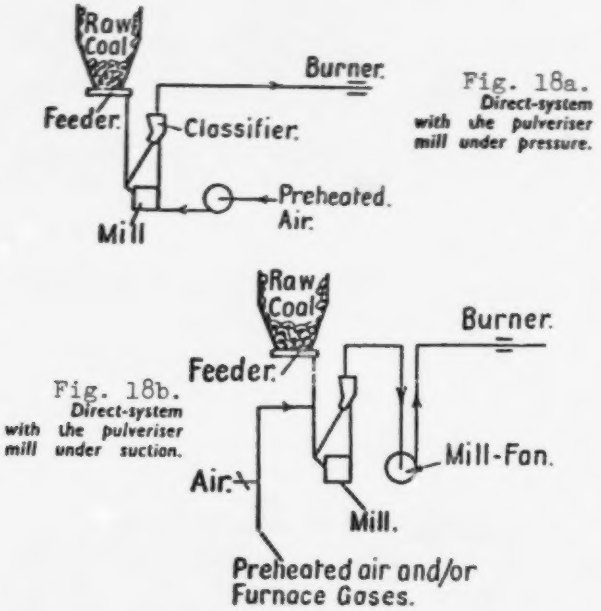


Fig. 18a. Direct-system with the pulveriser mill under pressure.

Fig. 18b. Direct-system with the pulveriser mill under suction.

Figure 18.

The "bin and feeder" systems (Figures 19a, b) permit the separation of the drying-grinding circuit from that of transporting the fuel to the burner, so that the coal can be injected into the flame by a prescribed proportion of the combustion air. "Bin and feeder" systems are more complex in their operation, require more precaution particularly when the dried pulverized coal is stored.

An example of how the suitable choice of the coal preparation system can be used for improving plant efficiency is shown in Figure 20[23]. Here the total amount of flue gas is recirculated and used as drying medium for a high moisture lignite. The flue gas can, in this way, be cooled down to below 100°C instead of the usual 200°C when expensive heat exchangers in the boiler have to be protected from low temperature corrosion.

Fig. 19a. **Open-circuit with storage.**

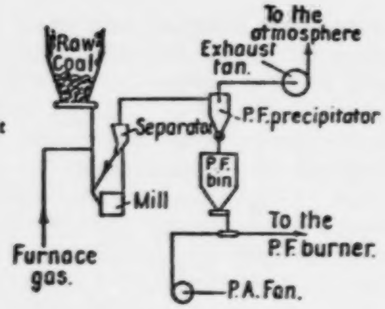

Raw Coal
To the atmosphere
Exhaust fan.
Separator
P.F. precipitator
P.F. bin
Mill
To the P.F. burner.
Furnace gas.
P.A. Fan.

Fig. 19b. **Closed-circuit with storage.**

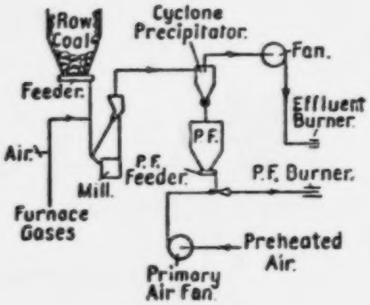

Raw Coal
Cyclone Precipitator.
Fan.
Feeder.
Effluent Burner.
P.F.
Air.
P.F. Feeder.
Mill.
P.F. Burner.
Furnace Gases
Preheated Air.
Primary Air Fan.

Fig. 19. "Bin and Feeder" Systems.

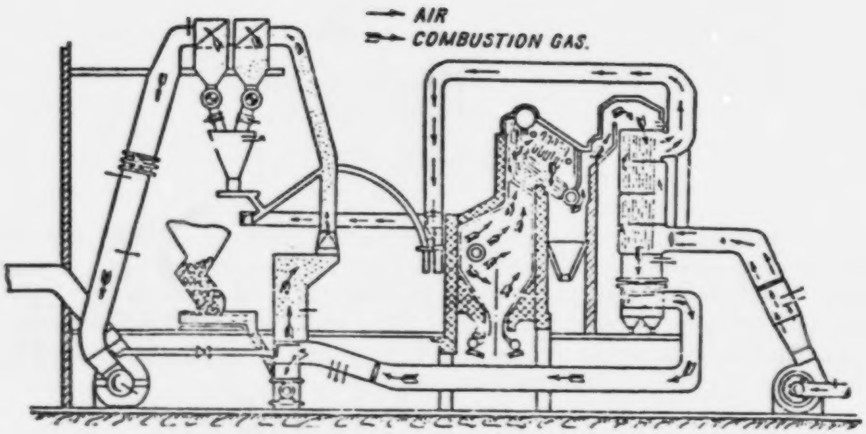

AIR
COMBUSTION GAS.

Fig. 20. Applied Open-Circuit System with Storage. (After P.N. Kendys, World Power Conference, 1956. Report No. 24862/17.)

In the other example the combination of a "bin and feeder" coal preparation system and a regenerative-type burner has been applied to solve the load following problem when burning a low grade coal[24]. Figure 21 shows the arrangement of the pilot burner in relation to the main burners in a corner-fired combustion chamber and Figure 22 illustrates the schematic of the recuperative-type burner. The high air preheat (650°C), the specially fine grinding (90% <44 µm), and the ability to feed the coal with the optimum primary air fraction make the pilot burner operation highly stable and capable of producing ignition in the otherwise unstable main burners.

While problems relating to the emissions of combustible particulates, and NO_x are amenable to solutions by combustion modification (staged combustion, coal preparation alterations, controlled heat extraction from the flame), the SO_2 emission control requires cumbersome and expensive "add-on" devices for pulverized coal-fired boilers.

This difficulty is the main reason in the considerable interest in a new, advanced combustion system, the fluidized combustion of coal.

FLUIDIZED COAL COMBUSTION

Fluidized combustion of coal involves the burning of coal particles--normally in the millimeter size range--in a hot fluidized bed of inert solids. The burning particles account for less than 2% weight of the total bed solids, more than 98% being coal ash and limestone or dolomite, the latter of which may be added for sulphur retention in the bed. The bed temperature is usually 750°C-950°C where the lower temperature is a combustion stability limit while the higher temperature is the ceiling for clinker-free operation of the bed.

An impetus was given to the development of fluidized combustion by the recognition that heat exchange surfaces immersed in the bed enable good control of the bed temperature to be achieved, without any detrimental effect upon mixing, i.e., solids recirculation in the bed. Experimental studies carried out in the early 60's at BCURA and the National Coal Board in Britain[25] and at Pope Evans and Robbins in the USA under contract to the Office of Coal Research to develop a coal-fired package boiler[26] showed that coal-burning fluidized beds can be operated with 18-20% excess air at temperatures lower than those at which ash clinkering occurs, and that due to the relatively low temperature in the bed the emission of nitrogen oxides is lower and little or no vaporization of alkali salts and of silica occurs. (The condensation of these vapours on heating surfaces is causing unpleasant deposit formation.) When limestone or dolomite is added to the bed material, the emission of sulphur dioxide can be reduced.

The Combustion of Coal in the Fluidized Bed

In the fluidized bed the solid particles are kept in a boiling-type motion by the gas supplied through the distributor plate which supports the bed (Figure 23). When the gas velocity is increased beyond a certain value, two phases are formed in a fluidized bed: a dense or particulate phase and a lean or bubble phase. The coal injected into the bed will find its way to the dense phase while most of the air introduced as

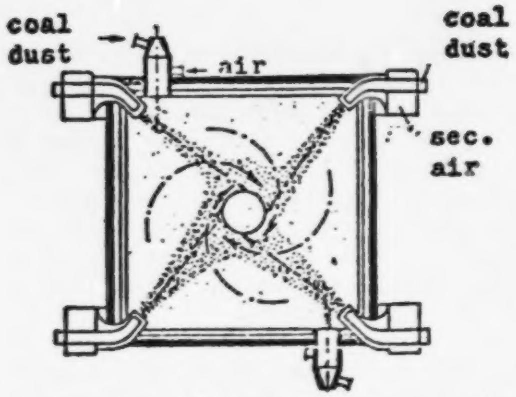

coal
dust
air
coal
dust
sec.
air

Fig. 21. Ignition Aid by Pilot Burners (Ref. 24).

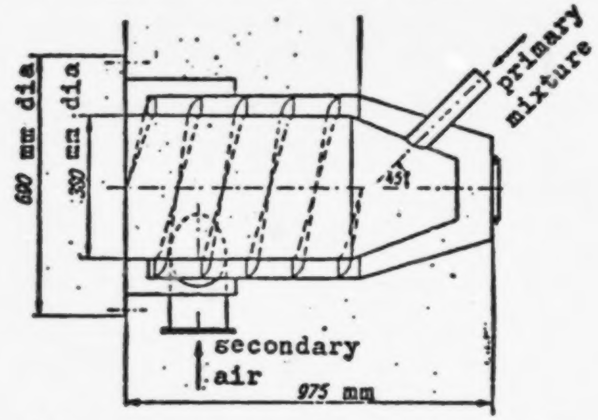

600 mm dia
300 mm dia
primary mixture
45°
secondary
air
975 mm

Fig. 22. Schematic of Pilot Burner for Low Grade Pulverized Coal (Ref. 24).

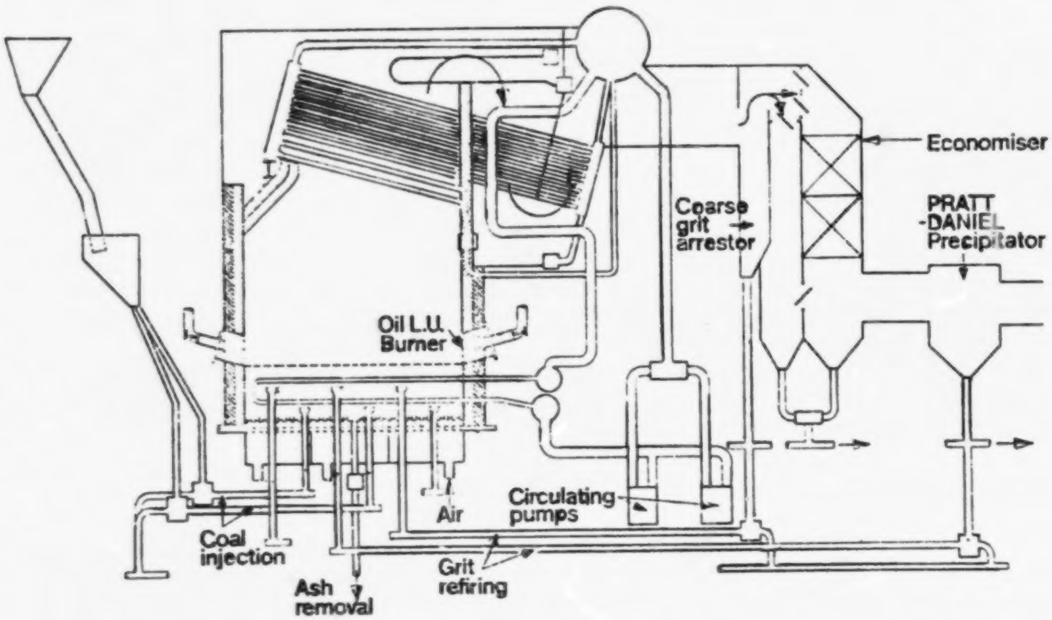

Economiser
Coarse grit arrestor
PRATT -DANIEL Precipitator
Oil L.U. Burner
Circulating pumps
Air
Coal injection
Ash removal
Grit refiring

Fig. 23. BCSL Fluidized Combustion Water-Tube Boiler.

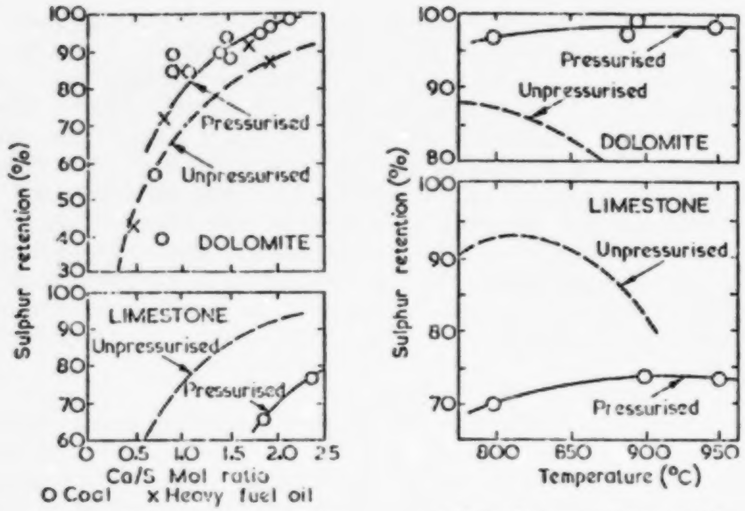
fluidizing air will rise through the bed in the form of bubbles[27]. The coal particles are larger than in pulverized combustion (mm size range) and their combustion is, normally, external-diffusion limited. At the low temperature limit of operation, however, at around 650°C, the slowest step in the overall reaction mechanism is most likely the desorption step in the chemisorption reaction at the coal surface. The oxygen concentration in the dense phase is low (1-3%), and an important factor in the rate of burning of the coal particle is the rate at which oxygen will diffuse from the bubble to the dense phase. The basic considerations and methods of calculation of combustion of coal particles have been established by Avedesian and Davidson[28]. Extensive theoretical and experimental research to develop further this theory is in progress at MIT.

Figure 24 shows the reduction of sulphur emission that can be achieved in fluidized combustion by the use of sorbents, limestone of dolomite in the bed. The NO emission determined in a number of pilot plant experiments and plotted as a function of bed temperature is given in Figure 25. Recent studies of the formation and destruction of NO in fluidized combustion processes have shown significant potential for the further reduction of NO emission[29].

There are several fluidized combustors in industrial operation and their present development can be considered to have reached the stage for application in industrial process heat or power generation systems. The scaling up of fluidized combustion to utility size boilers requires some further research and development: an improved coal feed system would have to be developed which does not require one feed point for every MW thermal input, and further studies would have to be carried out to ensure that superheater tubes immersed in the fluidized bed have comparable life time to steam generating tubes in the bed. Figure 26 shows the variation of the enthalpy composition of steam (i.e., liquid heat, latent heat and superheat) as a function of steam pressure. It can be seen that as the steam pressure rises, the latent heat proportion of the total enthalpy decreases. As the steam pressure rises beyond a value (>1500 psi), it becomes difficult to maintain a balance between the heat that has to be extracted from the bed to maintain its temperature below 900°C and the latent heat proportion of the steam generated in the bed; additional bed cooling by superheater tubes becomes necessary. This explains the need for further research on the corrosion-erosion of superheater tubes immersed in the bed, before fluidized combustion can be safely applied to large utility boilers.

CONCLUSIONS

An attempt has been made to present coal combustion systems from the point of view of the physical-chemical process that the coal and accompanying mineral matter undergo during combustion and by considering the requirements of plant and power generating cycle efficiency. It was considered that the development of coal combustion systems was closely tied to that of steam raising plant, that the transition from stoker firing to pulverized coal combustion occurred because the latter could be scaled up more easily to larger units, produced higher combustion efficiencies at lower excess air and could make use of higher air preheat which in turn was thermodynamically advantageous in power generating cycles.



Effect of Ca/S mol ratio on sulphur

Effect of temperature on sulphur

Figure 24.

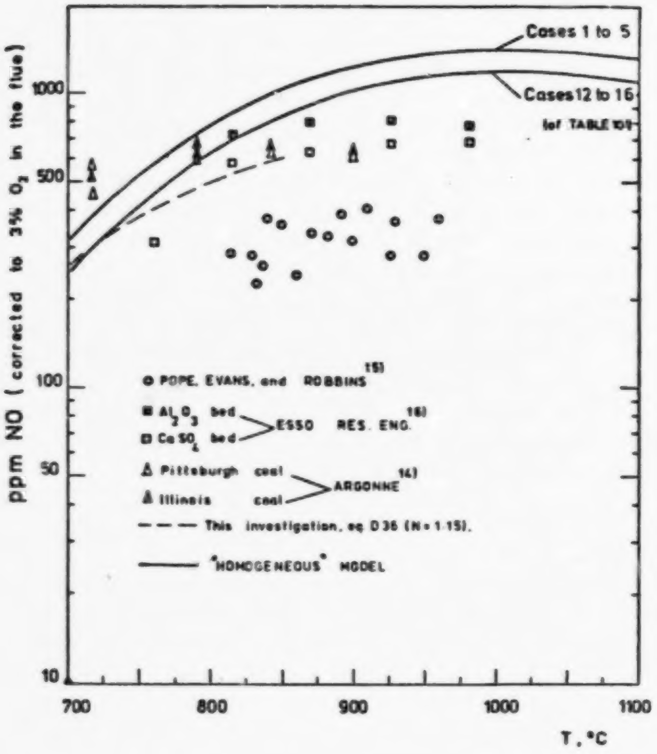


Fig. 25. NO Emissions from Fluidised Coal Combustion Comparison of Pooled Experimental Data with the Predictions of the Homogeneous Model.

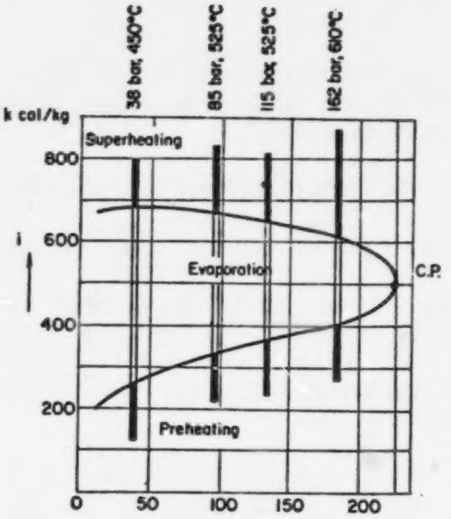


Fig. 26. Enthalpy Pressure Diagram of Water.

Fluidized coal combustion, a new advanced system, has the added advantage of being capable of retaining sulphur in the bed and it promises also significantly lower emission of NO_x. Due to its lower operating temperature, fewer or no submicron particulates are emitted from fluidized combustors. This system which is ready for application for smaller industrial combustion systems requires further concerted research for its application to utility-size power generators and for combined gas turbine-steam cycle operation.

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POLLUTANT FORMATION DURING COAL COMBUSTION

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1.0 INTRODUCTION

Increased coal utilization is undoubtedly the key to decreased reliance upon imported crude oil and energy independence. However, the methods which will be used in the next three decades to increase considerably the amount of energy being supplied from coal are open to question. Economic and environmental considerations will be factors in the choice of several available energy conversion alternatives since there is a need to utilize coal in an efficient, but environmentally acceptable manner. Coal contains constituents which have the potential to form pollutants which might be emitted into the atmosphere during the energy conversion process. These constituents are:

- Sulfur which forms SO_2 and SO_3 under oxidizing conditions.
- Mineral matter which results from the biological, chemical and environmental conditions existing during the formation of coal and is vaporized or converted to ash or slag during combustion. In a study of 65 Illinois coals Gluskoter(1) found that the mineral content ranged from 9.4 to 22.3 percent. Coal contains almost all the elements in the periodic table.
- Nitrogen which can also be oxidized to give nitrogen oxides (NO_x).

The above compounds, together with the products of incomplete combustion (CO, hydrocarbons, carbonaceous particulates and large molecular weight organic molecules), are potential pollutants resulting from coal utilization. Economics of pollution control are extremely important with regard to the increased utilization of coal as a fuel.

For one of the major pollutants produced from coal, sulfur, the choice is one of removal from the fuel or from the products of combustion. Removal from the fuel involves the production of a liquid or gaseous fuel or a clean, solid fuel. Coal gasification converts the majority of the sulfur to hydrogen sulfide which is then scrubbed from the fuel gas. Neglecting absorbant efficiency, the reduced gas volume ensures that the task of removing H_2S from the fuel gas is easier than the removal of SO_2 from the combustion products. Fluidized bed combustion of coal offers the possibility to burn coal as mined and yet control sulfur emissions by in-bed absorption of SO_2. Although coal gasification is not a new technology, its application to today's needs is

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far from straightforward and there are no operational fluidized bed combustors on a commercial scale. It appears that direct coal combustion in conventional plants provides the greatest opportunity for a rapid increase in coal utilization. The major problem associated with direct coal combustion is the control of three atmospheric pollutants — SO_x, NO_x and particulate matter.

This paper is primarily concerned with the formation of and control of nitrogen oxides since this is one pollutant which can be controlled by modifying the combustion process. Coal-fired utility and industrial boilers account for 37 percent of the stationary source emissions of NO_x, and gas- and oil-fired boilers contribute a further 16 percent to the total. The existing New Source Performance Standard (NSPS) for large coal-fired boilers is 0.7 lbs $NO_x/10^6$ Btu which is 3.5 and 2.3 times as high as the NSPS for gas- and oil-firing respectively. The increased emphasis on use of coal in large boilers will increase total NO_x emissions unless appropriate control technology is applied.

This paper does not provide a complete literature survey on the formation of nitrogen oxides in coal-fired systems. Only those references have been given which are necessary to illustrate a point or which contain controversial data. Before the fundamental aspects of NO_x formation are discussed, the state-of-the-art of NO_x control for coal-fired boilers will be reviewed. Finally, the prospects for advances in NO_x control technology for pulverized coal-fired boilers are discussed.

2.0 REVIEW OF NO_x CONTROL TECHNOLOGY

The reader is referred to several reports in the literature(2,3,4,5) which discuss the application of NO_x control technology to coal-fired boilers. The existing state-of-the-art is reviewed below:

- Firing Type. Coal can be burned crushed in cyclone furnaces, pulverized in tangential or wall-fired boilers, or spread as lump coal in stoker-fired boilers. NO_x emissions are normally highest for cyclone-firing, and wall-fired boilers characteristically emit more NO_x than tangential firing. Spreader stokers, which might have 50 percent of the heat released in the suspension phase, generally give higher emissions than underfeed stokers.

- Operational Parameters. Reduced load or reduced excess air operation tends to reduce emissions from all boiler types.

- Flue Gas Recirculation. The addition of cooled combustion products to the combustion air is not an effective method of controlling NO_x emissions from coal-fed boilers. This can be attributed to the predominance of fuel NO_x in the total emission from coal-fired units.

- Staged Heat Release. Staged heat release accomplished either by the use of overfire air ports or removing burners from service is an effective method of NO_x control.

- Burner Redesign. Redesign of the burner to decease the rate of fuel/air mixing for wall-fired burners reduces NO_x formation in pulverized coal flames.

3.0 NO_x FORMATION DURING COAL COMBUSTION

The nitrogen oxides emitted by coal-fired boilers are formed by the oxidation of molecular nitrogen (thermal NO_x) and nitrogen which is chemically bound in the fuel (fuel NO_x). Small-scale studies carried out by Pershing and Wendt(6) indicate that for pulverized coal-fired combustors the major portion of the emission can be attributed to fuel NO_x. However, under controlled conditions it might be expected that the thermal NO_x fraction will become more significant. The major portion of this discussion will be restricted to NO_x formation in pulverized coal combustion since this is the predominant method of coal utilization by direct combustion.

3.1 Coal Chemistry

In the restricted sense of this review coal chemistry refers to those changes which occur during the period of particle heating. Particles in pulverized coal flames are subjected to heating rates between 10,000 K/sec and 100,000 K/sec causing volatiles to be driven from the coal. The particles might swell and offgas as a jet, they might explode or the volatilization process might occur with little physical change in the particles. Blair et al(7) and Pohl and Sarofim(8) have shown that the total quantity of volatiles produced is a strong function of pyrolysis temperature.

Blair et al(7) carried out a series of controlled pyrolysis experiments with single particles and found that:

- Total nitrogen volatilized is a more sensitive function of pyrolysis temperature than is total mass pyrolyzed.
- Only 20 percent of the volatile fuel nitrogen appears to be released from the coal as light gases (HCN, NH_3).

This latter conclusion may have less significance because even though the initial nitrogen fragments may be heavy molecular weight compounds it is probable that these compounds undergo pyrolysis and that the nitrogen is converted to either HCN or NO depending upon the availability of oxygen. Of much more significance is the fact that the initial volatile fractions are low in nitrogen content. Thus these volatile gases have the opportunity to deplete the available oxygen before the major portion of the nitrogen-containing volatiles are evolved.

Studies(8) in a laminar flow furnace indicate that residence times of approximately one second are necessary at temperatures in excess of 1500K to reduce the nitrogen content of the char to less than 40 percent of the value of the original coal. Oxidation experiments in the same furnace clearly indicated that the conversion of char nitrogen to NO occurs with a lower efficiency than the conversion of coal nitrogen under comparable conditions of temperature and equivalence ratio.

In summary it appears that:

- At flame temperatures pyrolysis kinetics are sufficiently fast to suggest that in the absence of oxygen HCN would be the primary fuel nitrogen product.
- Increased temperatures decrease char nitrogen content.
- Initial volatile fractions are low in nitrogen species.
- The efficiency of char nitrogen conversion to NO is lower than that of the parent coal nitrogen to NO.

3.2 Homogeneous Gas Phase Reactions

The details of fuel NO kinetics are outside the scope of this paper other than to qualitatively describe those conditions which minimize fuel NO formation. Reaction zone stoichiometry appears to have the strongest influence on fuel NO formation, the conversion of fuel nitrogen to NO decreases rapidly as the mixture becomes fuel-rich. This can be accounted for by considering two competing reaction paths:

$$XN + O_x \rightarrow NO + \ldots \qquad (1)$$

which predominates in oxygen-rich mixtures and

$$XN + YN \rightarrow N_2 + \ldots \qquad (2)$$

which is faster in fuel-rich mixtures. There is also considerable evidence to suggest that NO is a necessary nitrogen specie for N_2 production. Another type of reaction which may be very significant in pulverized coal flames is the reduction of NO by hydrocarbon specie, e.g.,

$$NO + CH \rightarrow XN + \ldots \qquad (3)$$

thus allowing the production of nitrogen via reaction (2).

Premixed gaseous studies indicate that reaction zone temperature is not a significant factor in fuel NO production. However, the conversion of fuel nitrogen to NO appears to be greater in hydrogen flames than in hydrocarbon flames. The presence of sulfur appears to enhance the production of fuel NO in rich, premixed gaseous flames and two-phase turbulent diffusion flames suggesting that sulfur specie might interfere in the competing paths represented by reactions (1) and (2).

3.3 Coal Char Reactions

Char is that solid which remains after the volatile fractions have been driven from the coal particles. Char contains nitrogen; however, as noted earlier, the efficiency of char nitrogen conversion is less than that of the parent coal nitrogen. This can be attributed to the fact that the stagnant boundary layer surrounding the char particles is probably reducing. Thus even if the char nitrogen were to produce nitric oxide at the particle surface there is the possibility that it could be reduced to N_2 as it diffuses through the boundary layer. Surprisingly little concrete information is available concerning the production of NO from char nitrogen. Theoretical calculations carried out by Wendt and Shulze(9) suggest that the production of NO from char nitrogen is most sensitive to free stream oxygen concentration and temperature.

In a series of experiments designed to define probe conditions necessary for the measurement of NO in pulverized coal flames, Heap et al(10) showed that NO in nitrogen could be reduced by coal particles at temperatures above 200°C. Beér and co-workers(11) have shown that under fluidized bed conditions NO can also be reduced by coal char. Sarofim(12) has recently reported that coal char suspensions will also reduce NO to N_2 in the absence of oxygen. Consequently, it appears that NO produced in the early stages of heat release could be reduced by char in the burnout regions. Further research effort is necessary to ascertain whether heterogeneous NO reduction by char is an important phenomenon in pulverized coal flames.

3.4 Fuel/Air Contacting

Pulverized coal is burned in an air suspension. Fuel/air mixing, entrainment of recirculated combustion products, particle heating, volatile evolution, volatile combustion and char oxidation occur almost simultaneously. The major factor controlling the emission of nitrogen oxides is the fuel/air contacting process since this will affect:

- the rate of particle heating and the final particle temperature which will determine the proportion of the bound nitrogen remaining in the char;
- the atmosphere under which the volatile compounds react. If this is oxygen-rich then it would be expected to maximize NO production;
- the residence time in any rich zone. The degree of conversion of fuel nitrogen fragments to N_2 or the reduction of NO to N_2 will depend upon residence time in the rich zone; and
- the rate of heat release and reaction zone quench rate which will affect the production of thermal NO.

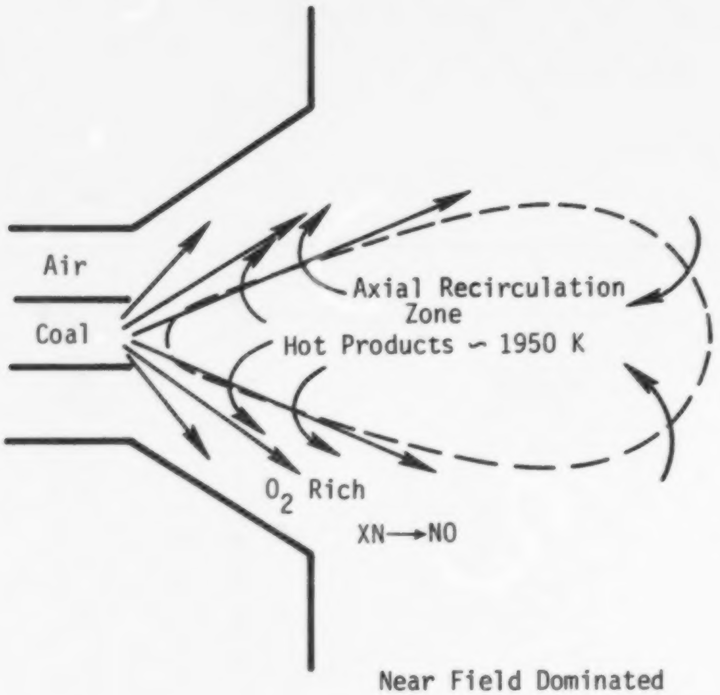
Heap et al(13) carried out a series of subscale experiments to establish the influence of fuel/air contacting on NO_x production in pulverized coal flames by varying burner parameters. These investigations demonstrated that NO_x emissions were very sensitive to the fuel/air mixing rates. Combinations of fuel injection method and axial and tangential velocity distributions produced the two major flame types sketched in Figure 1. The top sketch represents the conditions in a near-field dominated flame in which the coal and air are rapidly mixed. Maximum particle heating rates and stable ignition are provided by the entrainment of hot combustion products from an axial recirculation zone. These conditions are typical of flames in uncontrolled wall-fired boilers and maximize fuel NO_x formation since ample oxygen is available in the regions of coal volatilization. With the same coal, excess air level and air preheat temperature NO levels are reduced from approximately 800 ppm to 200 ppm by producing a high fineness ratio diffusion flame with a minimum oxygen level associated with the fuel jet. Provided there is a stable ignition front around the fuel jet the volatile fractions will remain in an oxygen-deficient atmosphere providing the opportunity for fuel nitrogen fragments to form N_2. The type of fuel/air contacting producing the high fineness ratio diffusion flame has many similarities with the processes occurring in corner-fired boilers whose NO_x emission levels are interestingly lower than uncontrolled emissions from wall-fired units.

Figure 2 taken from the work of Pershing and Wendt(6) provides experimental evidence to support the hypothesis presented above. These workers substituted argon for molecular nitrogen in the combustion "air," and thus the total emission can be attributed to fuel nitrogen conversion. Two different injectors were used which produced a near-field dominated flame (divergent injector) and a high fineness ratio diffusion flame (axial injector) and it can be seen that the fuel NO production is much less in the case of the high fineness ratio flame.

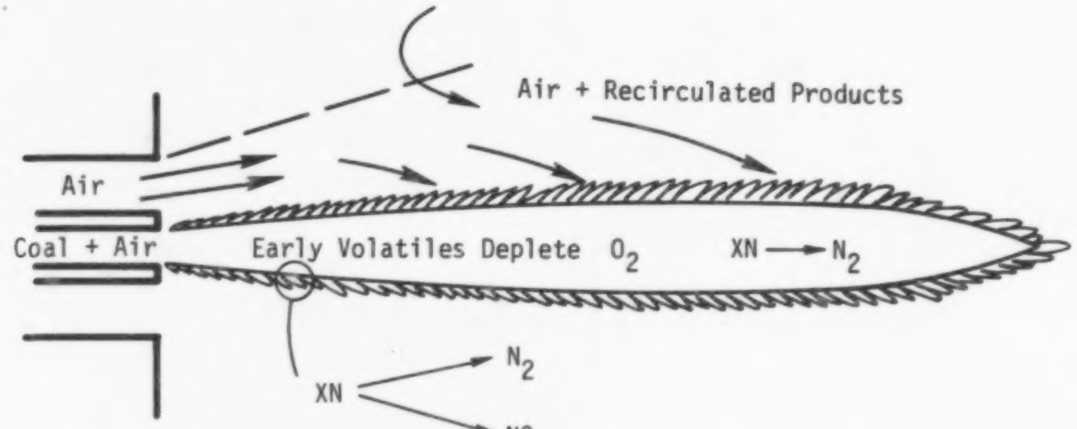
4.0 ADVANCED CONTROL TECHNOLOGY DEVELOPMENT

The stated goal of the U.S. Environmental Protection Agency is the development and demonstration of maximum NO_x control for stationary sources. This strategy is based upon the premise that stringent controls cannot be applied to mobile sources without incurring serious economic penalties. Consequently, if air quality is not to be degraded, more restrictive control must be imposed upon stationary sources. Conversion to coal or coal-derived liquids will tend to emphasize the significance of stationary source emissions, thus providing impetus for the development of advanced NO_x control technology.

The use of off-stoichiometric firing in combination with reduced load, low excess air operation and a modified burner design reduced NO_x levels to 200 ppm in an opposed wall-fired 270 MW boiler(14). Gershman et al(15) have reported on the development of a low NO_x prototype coal burner which is being sponsored by the EPA. This burner concept was based upon the subscale work of Heap et al(16) and relies upon distributed air addition which is explained schematically in the sketch shown in Figure 3. The air supply is divided into three streams. The distribution of axial and tangential velocity at the burner throat creates a high residence time, hot recirculation zone into which the coal is injected. The third air stream is injected at the periphery of the burner exit to provide an oxidizing envelope to prevent impingement of corrosive reducing gases on the furnace walls. The distributed air


Air
Coal
Axial Recirculation Zone
Hot Products ~ 1950 K
O2 Rich
XN → NO

Near Field Dominated


Air + Recirculated Products
Air
Coal + Air
Early Volatiles Deplete O2
XN → N2
XN
N2
NO

High Fineness Ratio Diffusion Flame

Figure 1. Major Flame Types

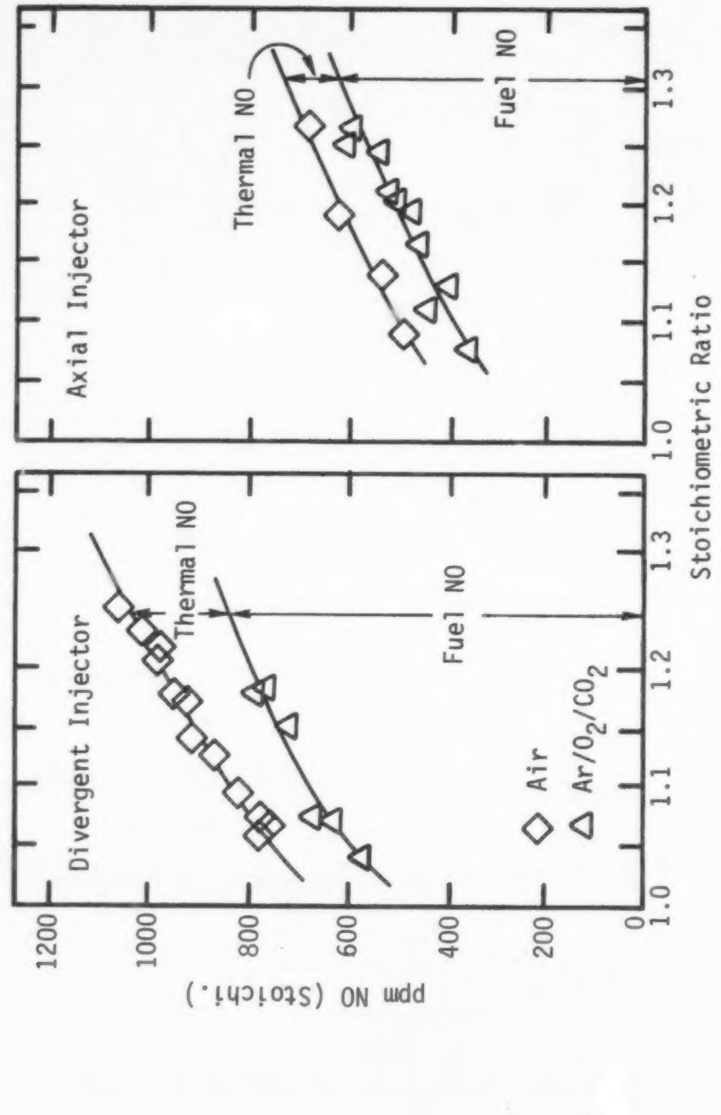


Figure 2. Comparison of Thermal and Fuel NO Production for Two Basic Flame Types (After Pershing and Wendt(6))

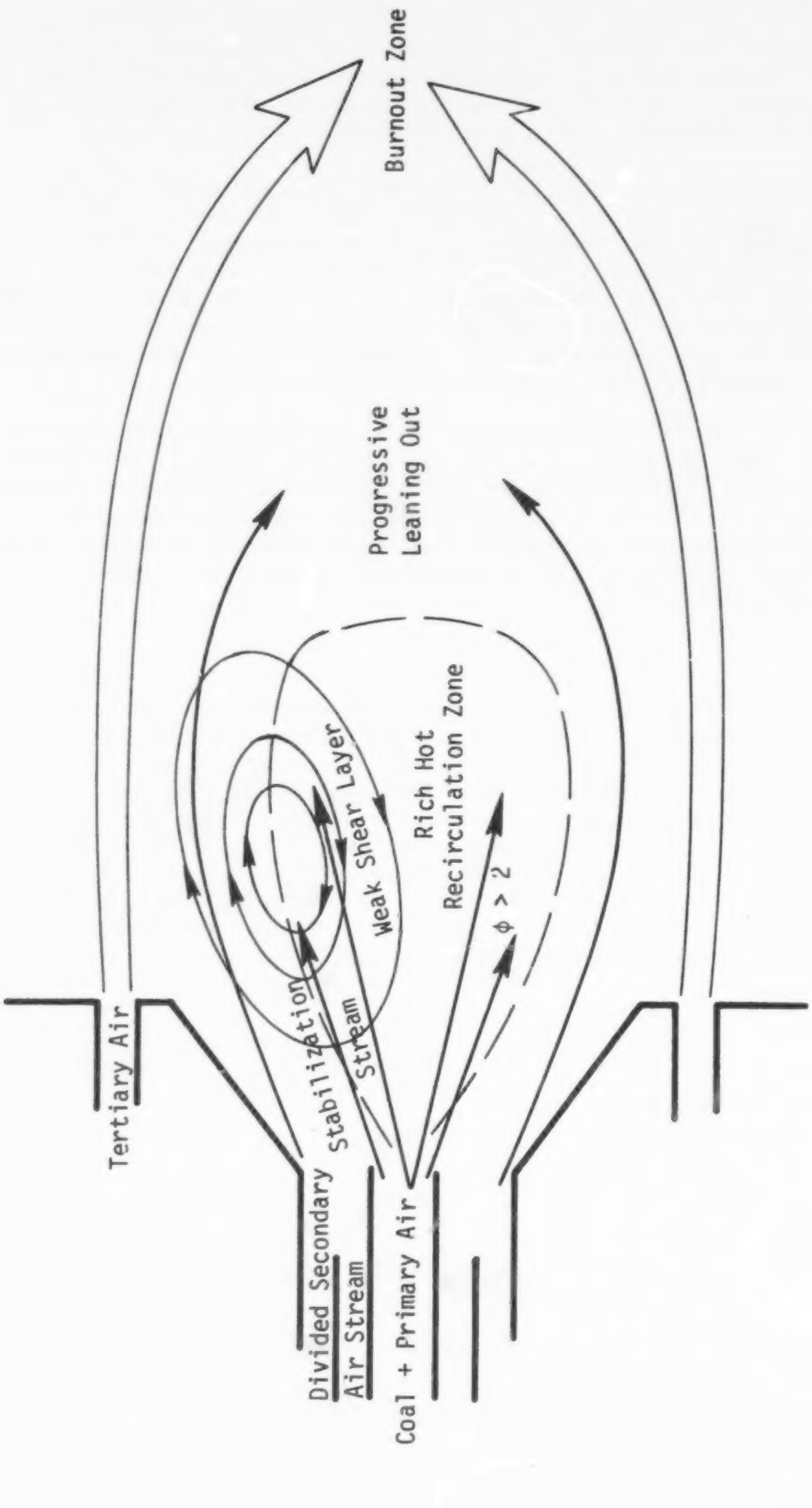

Burnout Zone
Progressive Leaning Out
Rich Hot Recirculation Zone
Weak Shear Layer
$\phi > 2$
Stabilization Stream
Tertiary Air
Divided Secondary Air Stream
Coal + Primary Air

Figure 3. Distributed Fuel/Air Mixing Concept

addition ensures that the coal first reacts in a rich region ($\phi>2$) thus minimizing NO production from volatile fuel nitrogen compounds in locally oxygen-rich pockets. Air is added to progressively lean out the system to maximize the time available for N_2 production from bound nitrogen species. Key elements in the design of this system are the fuel injector and the air flow distribution.

A test program is currently underway to investigate the performance of this concept at several scales (up to 120 x 10^6 Btu/hr) and with multiple burner arrays. Initial results are presented in Figure 4 which compares the performance of a single large burner in a cold wall, three-dimensional chamber with subscale work carried out by Heap in a refractory tunnel furnace. It can be seen that the performance of this prototype system is most promising. NO_x emission levels of 150 ppm appear possible without recourse to off-stoichiometric firing.

Brown et al(17) have investigated staged combustion systems for coal firing with long residence times in the primary section (of the order of 2 sec) and have achieved emission levels as low as 80 ppm. Residence time in the rich section is an important practical consideration because of its implication upon combustor size, heat loss and corrosion possibility. Total residence time to achieve 95 percent heat release in the distributed mixing burner is of the order of 0.3 sec.

SUMMARY

Coal contains trace species which form atmospheric pollutants during combustion. This paper has reviewed those factors controlling the formation of one pollutant, NO_x, and discussed methods of control based upon combustion modification. It appears that NO_x emissions from direct coal combustion can be controlled to levels substantially lower than existing New Source Performance Standards without the need for radical redesign of the combustion chamber of utility boilers. Minimum NO_x levels are likely to be achieved by removing all nitrogen from the solid phase under fuel-rich conditions and allowing the gaseous species to produce N_2 prior to second stage air addition.

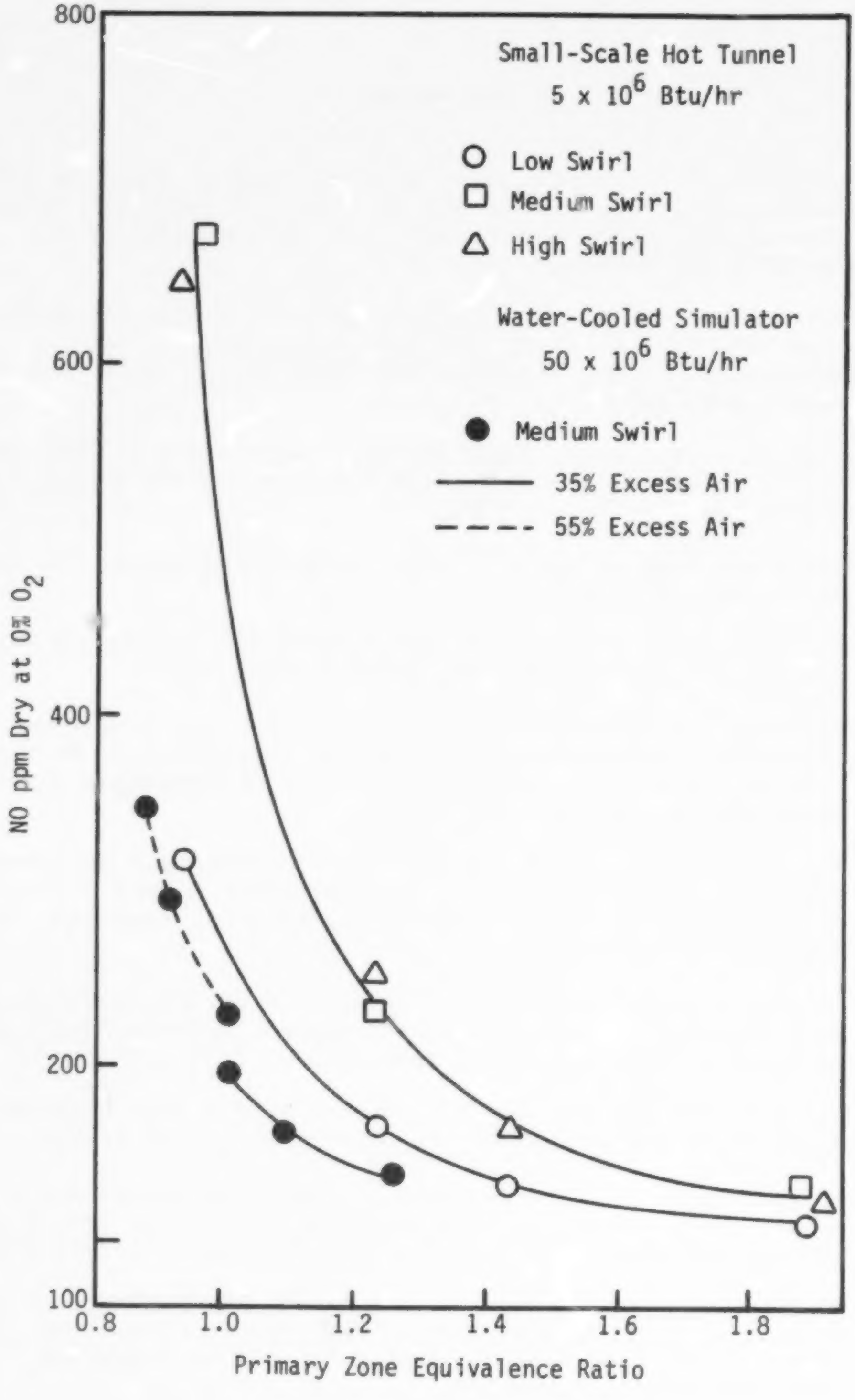


Figure 4. Test Results

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THE DUAL REGISTER PULVERIZED COAL BURNER: FIELD TEST RESULTS

by

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ABSTRACT

The Federal Environmental Protection Agency's "Standards of Performance for New Stationary Sources" limits the emissions of oxides of nitrogen for pulverized coals (other than lignite) to a maximum level of 0.7 lbs NO_2 per million Btu heat input to the boiler. To comply with the above standard, it was necessary to develop a new pulverized coal burner because the existing Babcock & Wilcox (B&W) standard high turbulence burner was not capable of producing NO_x emissions within the above limit.

B&W's judgmental criteria for the success of the new burner development was that the burner/furnace system be capable of reducing NO_x generation to levels below the EPA NO_x limit while maintaining carbon utilization equal to or higher than the former standard burner.

After extensive laboratory and field testing, the B&W Dual Register Burner was developed. The data obtained to date has shown that this burner is capable of operating below the existing NO_x limit without increasing unburned carbon and excess air levels over those experienced with the previous burner.

This paper discusses the NO_x results obtained to date utilizing the Dual Register Burner.

THE DUAL REGISTER BURNER

The Dual Register Pulverized Coal Fired Burner (Figure 1) is a limited turbulence, controlled diffusion flame burner designed to minimize the amount of fuel and air mixed at the burner to that required to obtain ignition and sustain stable combustion of the coal. A venturi mixing device is located in the coal nozzle to provide a homogeneous coal/primary air mixture at the burner. The remainder of the combustion air (secondary air) is introduced through two concentric air zones which surround the coal nozzle. The air flow to each air zone is independently controlled through inner and outer air zone registers. Adjustable spin vanes are located in the inner air zone to provide varying degrees of swirl to the inner air to control coal/air mixing during the combustion process.

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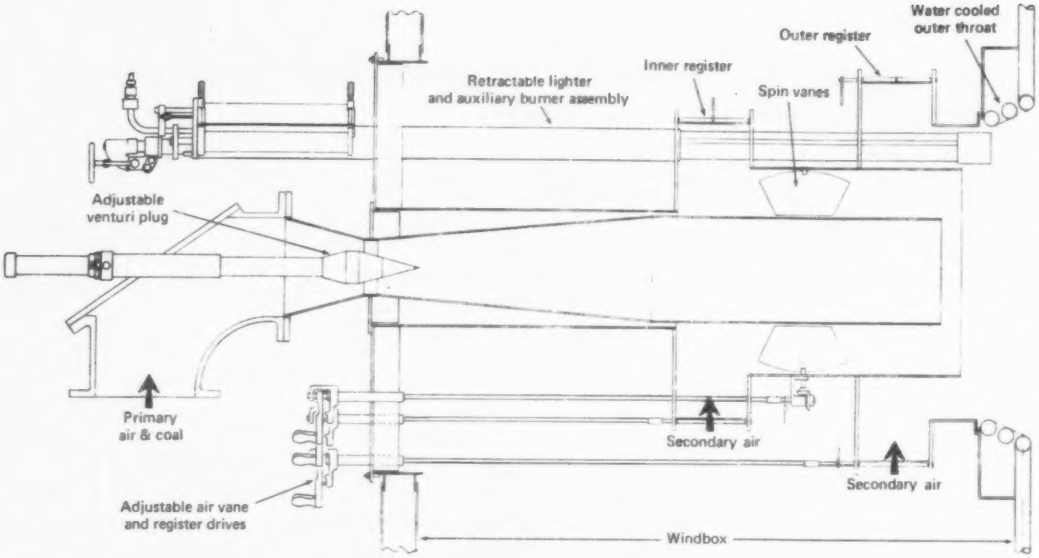

Water cooled outer throat
Outer register
Inner register
Retractable lighter and auxiliary burner assembly
Spin vanes
Adjustable venturi plug
Primary air & coal
Secondary air
Secondary air
Adjustable air vane and register drives
Windbox

Dual register burner

Figure 1

By controlling the mixing of the coal and air, the combustion process is initiated at the burner throat and the zone of completion can be varied in the furnace chamber. This method of delayed combustion reduces the high temperature zones at each burner. Thus the peak temperature in the furnace is lowered, minimizing the thermal conversion of combustion air nitrogen to NO_x. Also, through controlled fuel and air mixing, the oxygen availability is minimized during the process reducing fuel nitrogen conversion.

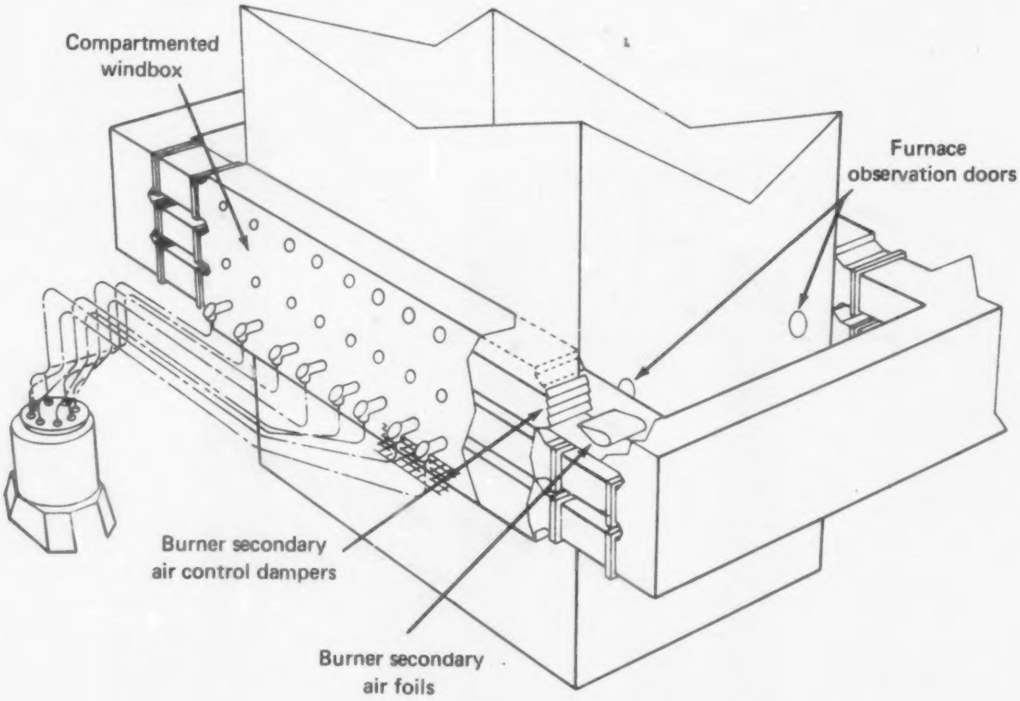
The Dual Register Burner lowers NO_x by delaying combustion and is not a staging device. Previous work on pulverized coal firing has shown that two-stage combustion is the most effective method of NO_x reduction. However, in reviewing overall unit performance, the Dual Register Burner has the following benefits over staging techniques:

1) The furnace is maintained in an oxidizing environment to minimize slagging and reduce the potential for furnace wall corrosion when burning high sulfur bituminous coal.

2) More complete carbon utilization through better air/coal mixing in the furnace.

3) Lower oxygen levels required with total combustion air admitted through the burners rather than above the burner zone.

In addition to the Dual Register Burner, the burner windbox design was changed to provide air flow control on a per pulverizer basis (Figure 2). This compartmented windbox permits careful control of fuel and air flows to each burner group. This permits operation with lower total excess air while maintaining an oxidizing atmosphere around each burner. The results are lower NO_x emissions and increased flexibility in the introduction of excess air to the burner zone for both slagging and NO_x control.

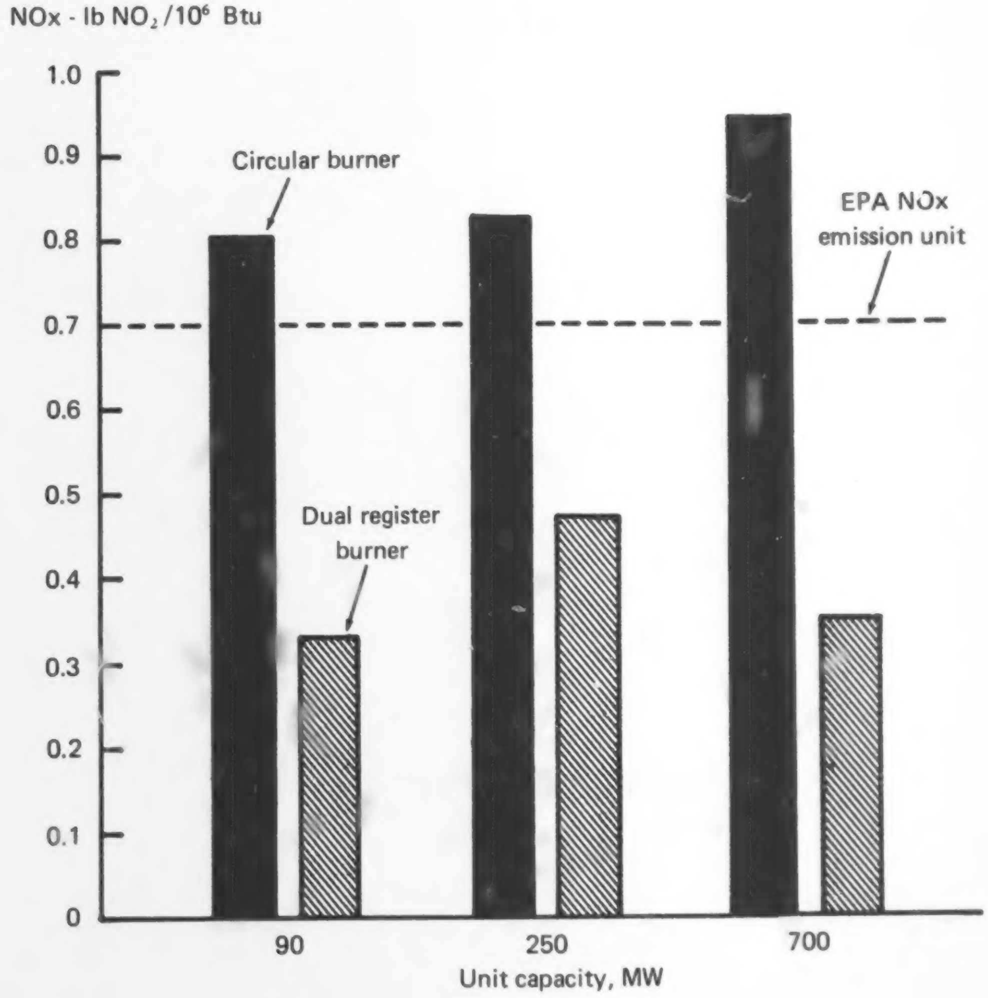

Compartmented windbox
Furnace observation doors
Burner secondary air control dampers
Burner secondary air foils

Pulverizer-burner system

Figure 2

FIELD TEST DATA

To date, three (3) Babcock & Wilcox pulverized coal-fired boilers equipped with the Dual Register Burner have been tested to determine NO_x emissions. The program for each unit consisted of a series of NO_x tests performed at various operating conditions over the load range. When operating the units at normal excess air required for combustion, the NO_x emissions were well below the present EPA limit of 0.7 lbs/10^6 Btu. Figure 3 is a summary of the full load NO_x emissions under normal



Comparison of NOx emissions circular burner vs dual register burner

Figure 3

conditions (15 - 17% excess air to the burners). The emissions range from 0.33 to 0.47 lbs/million Btu for the three (3) units, which vary in capacity from 90MW to 700 MW. Also, depicted in Figure 3 are the NO_x emissions obtained from similar units equipped with the high turbulence Circular Burner previously supplied by Babcock & Wilcox.

The direct data comparison indicates that a 45 to 60% reduction in NO_x is achievable through burner design. The majority of the reduction is attributable to controlled air/coal mixing in the furnace chamber. Through controlled mixing at the burner, the peak flame temperature is reduced thus minimizing the thermal NO_x formation at the burner. In addition, the controlled mixing decreases the oxygen available to react with the nitrogen chemically bound in the fuel.

The type of coal utilized also affects NO_x formation. The 90 and 700 MW units burn a sub-bituminous type coal while the 250MW unit burns a bituminous coal. A comparison of typical analysis for these two (2) coals (Figure 4) indicates why NO_x emissions are lower when firing sub-bituminous coal. The higher moisture content of the sub-bituminous fuel (30.6% versus 8.5%) provides for lower thermal NO_x generation because of reduced furnace zone temperatures due to the greater heat of vaporization required. The nitrogen content of the coal also affects NO_x generation. Comparing the nitrogen content on a lbs. nitrogen/million Btu heat input basis (thereby eliminating variations in heating value), the fuel-contained nitrogen introduced to the furnace is 13% lower with sub-bituminous coal (0.67 versus 0.77 lbs N/million Btu).

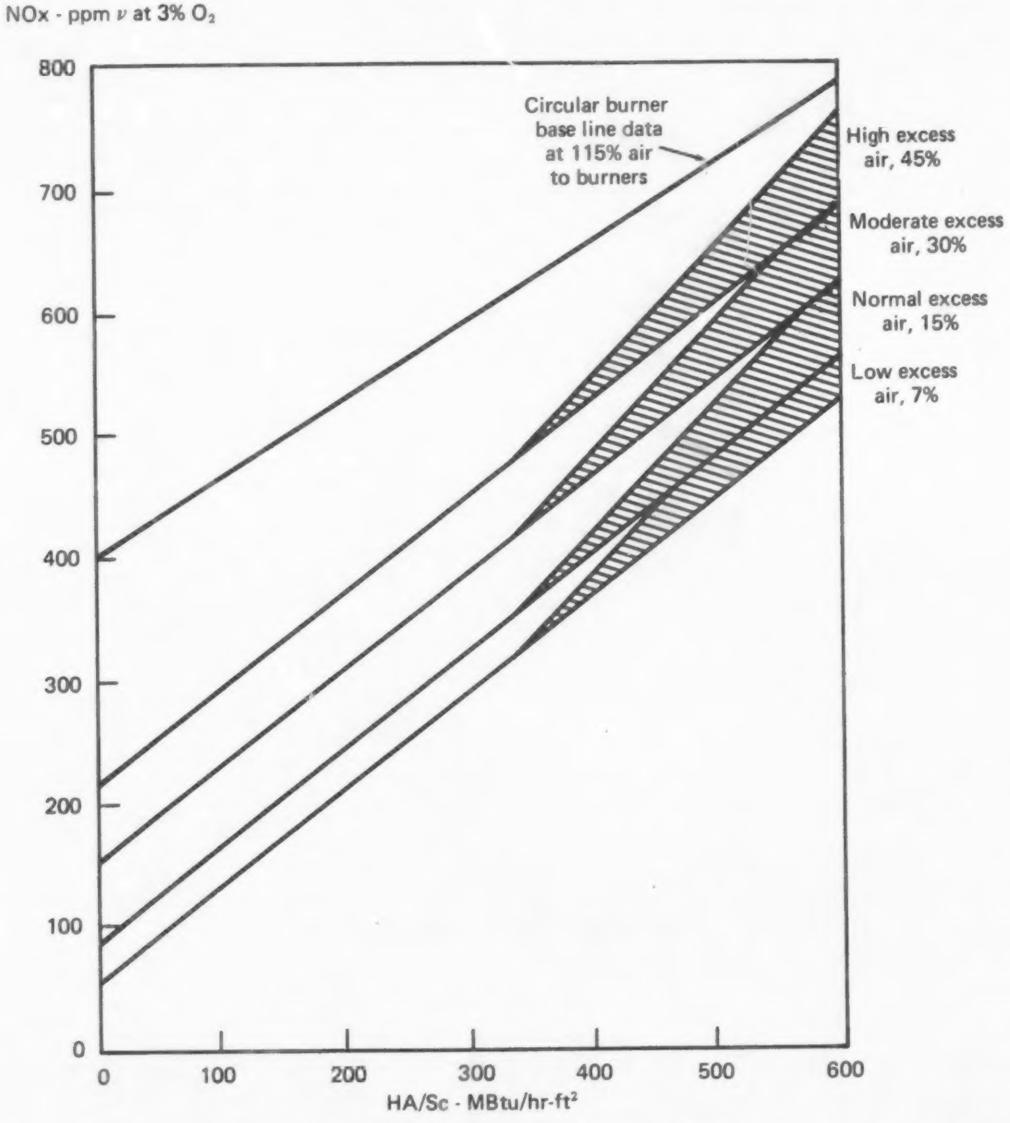
	Bituminous	Sub-Bituminous
Total moisture, %	8.5	30.6
Proximate analysis, % (dry)		
Volatile matter	30.8	45.5
Fixed carbon	54.8	47.5
Ash	14.4	7.0
Ultimate analysis, % (dry)		
Carbon	71.8	69.2
Hydrogen	4.9	5.0
Nitrogen	1.0	0.8
Sulfur	1.6	0.7
Ash	14.4	7.0
Oxygen	6.3	17.3
HHV, Btu/lb (dry)	13,060	11,950
Nitrogen, lb/10^6 Btu	0.77	0.67

Typical coal analyses

Figure 4

With less nitrogen available, the contribution of fuel bound nitrogen conversion is reduced.

In addition to variations in coal supply, the two principal parameters affecting NO_x formation are combustion zone temperature and oxygen availability. NO_x versus heat release rate in the burner zone of the furnace (HA/SC) for various excess air levels is plotted in Figure 5. The correlations were based on actual field data from the 250MW



Field test results

Figure 5

bituminous fired unit. Statistical analysis was used to develop the linear best fit curves from the test data.

The effect of furnace zone temperature is illustrated by the increase in NO_x for higher heat release rates. The NO_x increases 80 ppm per 100 MBtu/hr-ft^2. For a given unit, the larger the HA/SC, the higher the temperature will be in the burner zone of the furnace. NO_x generation attributable to thermal fixation will increase per the relationship. Since the thermal NO_x formation is extremely temperature sensitive at high temperatures, the shaded areas on Figure 5 represent the degree of uncertainty at the higher heat release rates. As the burner zone temperature approaches the threshold temperature, the rate of thermal NO_x fixation rapidly increases.

The formation of NO_x also requires oxygen availability and the greater the excess oxygen, the higher the NO_x generated. NO_x emissions versus excess air quantities ranging from 7% to 45% is plotted in Figure 5. Actual field data indicates NO_x emissions increase by 20 - 25 ppm per 5% increase in excess air. Utilization of the Dual Register Burner coupled with the compartmented windbox has provided proper control of air and fuel mixing which minimizes air requirements thus limiting NO_x formation.

SUMMARY

Results from the three (3) pulverized coal units tested to date show the Dual Register Burner to be an effective tool for NO_x emission control. NO_x levels 40 to 50% lower than those achievable with the high turbulence Circular Burner are attained through limited turbulence combustion. At the same time, carbon utilization has been maintained at levels comparable to those obtained utilizing a high turbulence Circular Burner. The Dual Register Burner provides low NO_x emission without sacrificing unit efficiency.

The data acquisition and analysis program as reported herein will continue to provide data to update and improve future units. It is expected that by the end of 1977 NO_x and performance data will be available from an additional four (4) units now in the final stages of start-up. These tests will include units firing both bituminous and sub-bituminous grade coals.

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COAL-OIL MIXTURE COMBUSTION IN BOILERS - AN UPDATE

By
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1. INTRODUCTION

As a result of unavailability and increased cost of fuel oil for power plants, the nation faces large capital outlays in converting the existing oil-fired steam generating capacities to coal burning. Also, power plants that have been converted from coal to oil firing would be converted back to coal burning. At some plants, however, it may not be practical to convert to coal burning due to lack of coal storage/coal handling facilities or high capital cost and short remaining life of the units. An alternative to the above could be to burn pulverized coal-oil mixture (COM). This will be a near-term alternative to minimize the expense and complexities of total conversion, while at the same time reducing the dependency on foreign oil.

In general, by making use of coal-oil mixture, a utility will be able to take advantage of relatively low prices and more stable supply of this country's coal reserves. Coal-oil mixture will provide an interim solution for short-term coal utilization, before new technologies such as coal gasification, coal liquefaction, and solvent refined coal become commercially available. Another extremely attractive feature of the coal-oil mixture combustion concept is that an extensive new technology doesn't need to be developed before application of coal-oil mixture. The fuel could be made commercially available within two to four years, with a minimum requirement for new equipment and technology.

The paper presented is devoted to: 1) discussion of past studies on coal-oil mixture stability; 2) a brief discussion on experimental programs of combustion of coal-oil mixture at Pittsburgh Energy Research Center (PERC) and Institute of Gas Technology (IGT); and 3) a review of coal-oil mixture development programs at General Motors and New England Power Service Company.

2. HISTORICAL BACKGROUND

Since 1879[1], several attempts have been made to burn coal-oil mixture. Combustion of coal-oil slurry was first tried in ocean-going vessels and locomotives to save bunker space and minimize the risk of fire in the storage of coal. In 1932[2], the Cunard liner Scythia steamed from Liverpool to New York and back with one boiler fired on a coal-oil mixture. However, the principal disadvantage of such a fuel was the difficulty of maintaining the coal in suspension. During World War II, the research in coal-oil mixture was again resumed in Japan, Germany, and in this country, and burning of coal-oil mixture was tried on a small scale. However, there has been no large-scale application of this technology. More recently, several programs

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have been initiated in this country funded by ERDA or by private funds for development of coal-oil mixture technology.

3. COAL-OIL MIXTURE PREPARATION

Coal-oil mixture can be prepared by simply mixing finely ground coal in No. 6 residual oil and providing continuous agitation to prevent settling. Alternatively, a stabilized coal-oil mixture may be prepared by adding a chemical additive to a mixture of pulverized coal and No. 6 residual fuel oil with or without water. A stable mixture is essential for good flame stability and also to keep the coal from settling in tanks, heat exchangers, valves and pipelines. Evidently, both of these systems have their own merits. Whereas it may be possible to eliminate continuous agitation by use of chemical additives, current cost of these additives is very high. Further research and development needs to be done to investigate possibilities of less expensive additives that can be used for stabilization of coal-oil mixture.

4. STABILITY AND VISCOSITY OF COAL-OIL MIXTURE

The stability of coal-oil mixture has been studied by various researchers in the past. In the laboratory work reported in 1944 by Barkley[3], et al., it was observed that the stability of the mixture increased considerably with increase in percentage of coal in coal-oil mixture. Also, the effect of temperature, as well as particle size on stability of the mixture, was studied. Figure 1 shows the effect of percentage of coal in mixture on stability at 77°F. It was observed

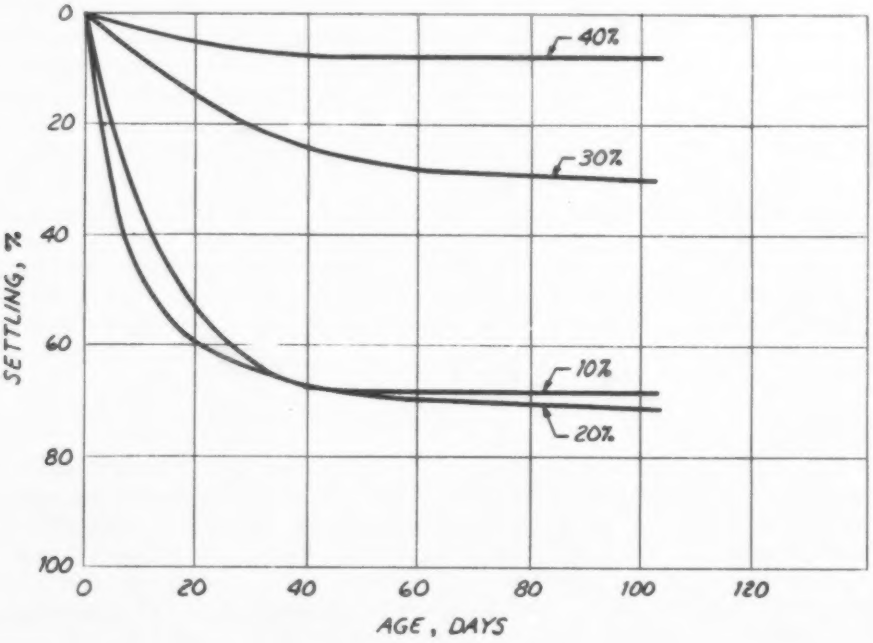

Figure 1. Effect of percentage of coal in mixture on stability at 77F, Ref. 3.

that the mixtures are relatively stable when the maximum particle size does not exceed 230 mesh. Furthermore, the distribution of the size of coal affected the stability of the mixture considerably. An addition of even small quantities of coarser materials in the coal-oil mixture adversely affected the stability of the mixture.

The viscosity of the mixture increases markedly in the region of 40 to 45 percent of coal by weight (Figure 2). Also, the rapid rise in viscosity in this range was found to be relatively independent of the viscosity of the oil and temperature of the mixture. A rapid increase in viscosity was also observed when the coal size was reduced from 230 mesh to 230/325 mesh.

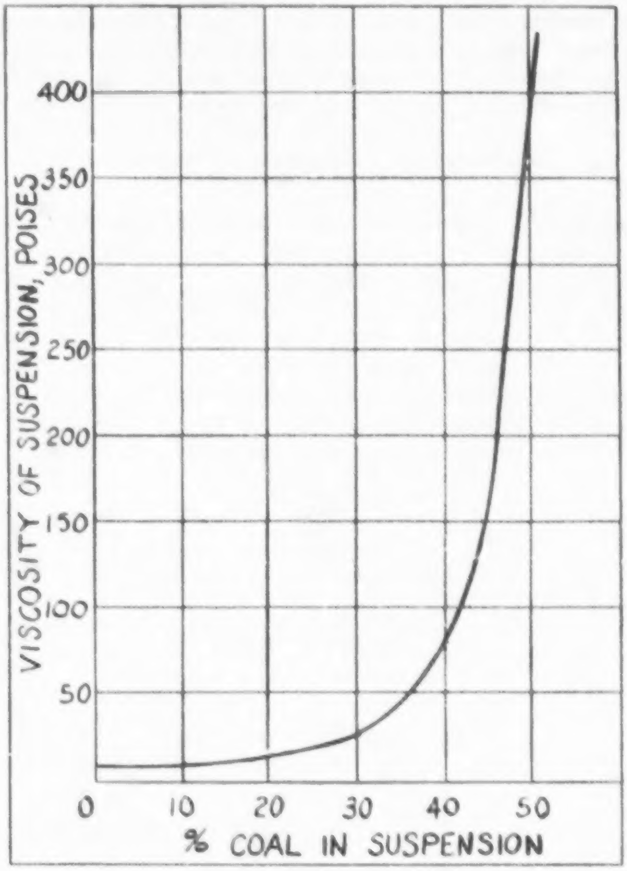

Figure 2. Effect of percentage of coal in mixture on viscosity at 77F, Ref. 3.

In view of the results reported above, from the point of view of stability and viscosity of the mixture, the amount of coal in the mixture should be limited to 40 percent, and the coal size to 98 percent passing through 230 mesh screen. For practical purposes and to reduce grinding and pumping costs, however, it is desirable to limit the percentage of coal in the coal-oil mixture to 30 percent, and coal size to 80 percent passing through 200 mesh.

5. COAL-OIL MIXTURE COMBUSTION DEMONSTRATIONS

The combustion of coal-oil mixture has recently been investigated at Pittsburgh Energy Research Center and at General Motors facility in Saginaw, Michigan. The later research was sponsored by ERDA, EPRI[4], General Motors, and more than 15 companies including New England Power Service Company. Besides these investigations for application of coal-oil mixture to package boilers, ERDA is partially funding the development and demonstration of coal-oil mixture combustion at two utility plants: namely, New England Power Company's 80 MW unit at Salem Harbor Station; and City Public Service of San Antonio's 69 MW unit.

6. EXPERIMENTAL PROGRAM AT PERC

Coal-oil mixture combustion studies were conducted at Pittsburgh Energy Research Center[5] of ERDA in June 1975. The principal objectives of these studies were to determine major problem areas while firing 20% coal-oil mixture in a package boiler designed to burn oil or gas and to determine corrosion and deposits after 1,000 hours of operation.

A new burner designed for No. 6 fuel oil was installed in a surplus 100 hp 4 pass Cleaver-Brooks fire tube boiler and a coal-oil mixture preparation and feed system was assembled. Figure 3 shows a simplified flow diagram of the 100 H.P. unit. This system was intentionally assembled utilizing existing or readily available equipment to as-

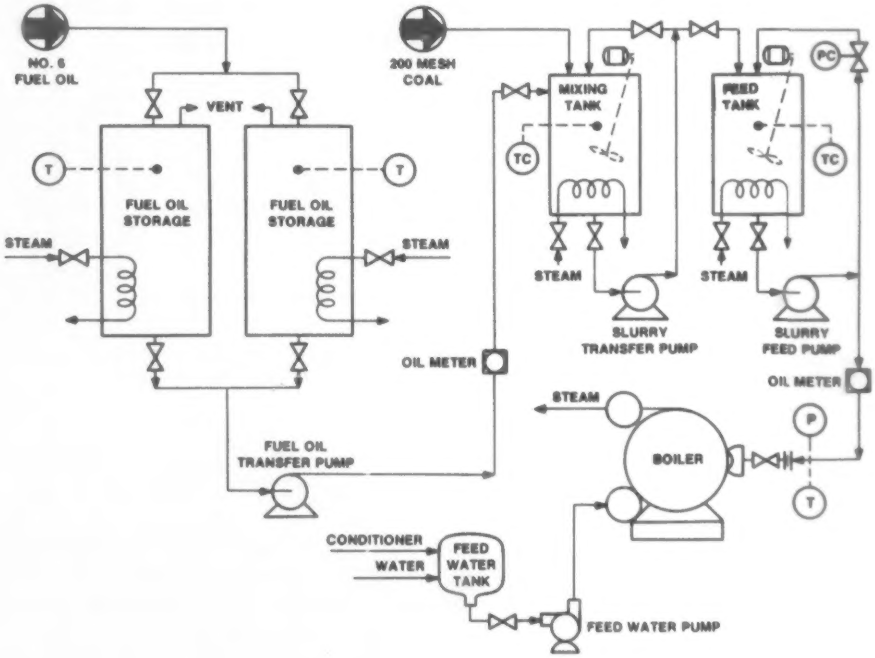
NO. 6 FUEL OIL
VENT
T
FUEL OIL STORAGE
FUEL OIL STORAGE
T
STEAM
STEAM
200 MESH COAL
MIXING TANK
FEED TANK
PC
TC
TC
STEAM
STEAM
SLURRY TRANSFER PUMP
SLURRY FEED PUMP
OIL METER
OIL METER
STEAM
P
BOILER
T
FUEL OIL TRANSFER PUMP
CONDITIONER
WATER
FEED WATER TANK
FEED WATER PUMP

Figure 3. Simplified flow diagram of the 100 H.P. coal-oil mixture combustion test facility, Ref. 5.

certain the minimum equipment changes necessary to adapt an oil-fired boiler to coal-oil mixture combustion. Modifications and/or improvements were made in control and instrumentation as required during the experimental program.

In general, the program concluded that no slagging was experienced in the boiler, and carbon combustion efficiency was more than 99%. Boiler efficiency tests indicated that the efficiency obtained with coal-oil mixture combustion was essentially the same as that obtained with fuel oil. Some char deposition was experienced when firing at a high rate due to an excessively wide spray pattern that produced flame impingement on the relatively narrow combustion chamber. This became progressively worse with time, as the orifices in the brass nozzle became enlarged due to erosion and the atomization pattern was changed. This problem was eliminated by modifying the combustion air diffuser to obtain the desired flow pattern and fabricating nozzles of stainless steel with a narrower spray pattern. Inspection of the boiler tubes after the completion of the 1,000-hour test revealed only a light deposit on the internal tube surfaces. The carbon monoxide concentration in the flue gas was slightly higher than that obtained with oil (260 vs. 160 ppm) but was acceptably low. Similarly, the NO_x emissions were also slightly higher reflecting the higher fuel bound nitrogen content of the coal-oil slurry. Sections of tubes were taken from within the passes of the boiler to determine the effect of corrosion/erosion. No evidence of severe corrosion attack was observed. Also, there was no evidence of inter-granular or subscale corrosion attack on any of the test specimens.

7. COMBUSTION TESTS AT GENERAL MOTORS FACILITY

In 1974, General Motors[6] had a three-day, 10,000-gallon pilot test using a mixture of No. 2 fuel oil and pulverized coal delivered to their plant in Saginaw, Michigan. Some of the technical problems encountered in that demonstration were settling of the coal out of the mixture, increased viscosity of the mixture, and problems associated with coal-oil mixture preparation techniques. A development program was initiated to solve these problems, and to burn coal-oil mixture with No. 6 oil in existing oil-fired package boilers. In March of 1975, a consortium of companies and organizations was established. This included U. S. Energy Research and Development Administration, Electric Power Research Institute, several utilities including New England Power Service Company, coal suppliers, and chemical manufacturers. Preliminary work was conducted to gain specific information in regard to fuel-oil and coal selection, fuel blending, fuel characterization, fuel atomization, and optimization of combustion before proceeding to extensive tests. The results in general indicated that coal-oil mixture should perform as well as residual fuel oil using conventional equipment.

8. COMBUSTION TESTS AT IGT

Detailed combustion tests were carried out at the Institute of Gas Technology, Chicago, to identify possible operational problem areas and define combustion characteristics for coal-oil mixture. These tests involved the use of steam and air atomized burners on coal-oil mixture in a rectangular furnace to investigate flame stability, geometry, emissivity and NO_x emissions. The results of these tests indicated that the combustion flame produced from coal-oil mixture (30-50 weight percent coal) using conventional atomizing nozzles was stable with good geometry. The flame was also very similar to the flame produced by straight No. 6 fuel oil. Good carbon burnout within the test chamber was noted. As expected, the particulate emissions were higher than for oil only. The coal-oil mixture's flame emissivities were the same as or higher than the emissivity values obtained from residual fuel oil. Furthermore, it was observed that the presence of 5% water in the fuel did not degrade combustion, and in fact appeared to enhance the atomization.

9. DEMONSTRATION AT GENERAL MOTORS FACILITY

Tests were carried on combustion of coal-oil mixture in a packaged oil-fired boiler rated at 120,000 pounds per hour steam capacity installed at the Chevrolet Nodular Iron Plant Power House in Saginaw, Michigan. A summary of the boiler specifications is given in Table 1.

TABLE 1

Test Boiler Specifications

Plant Boiler No.	5
Year Installed	1966
Boiler Manufacturer	CE-Wickes
Type	A
Pressure Standard	250
Rated Capacity (PPH)	120,000
No. of Drums	3
Heating Surface (Ft.^{2})	8,897
Furnace Heating Surface (Ft.^{2})	1,073
Furnace Volume (Cu. Ft.)	2,180
Furnace Width	7' 8-1/2"
Furnace Length	30' 8-3/4"
Gas Passes	Horiz.
Temp. Flue Gas Leaving Boiler (°F)	505
Number of Burners	2
Air Preheater	Yes
Gas Temp. Entering (°F)	505
Gas Temp. Leaving (°F)	353
Air Temp. Entering (°F)	134
Air Temp. Leaving (°F)	309
Heating Surface (Ft.^{2})	1,400
Stack Control Devices	None

This work has been carried out in two phases: Phase I, March to June 1976; Phase II, March to May 1977. The test boiler has a natural draft with no flue gas cleaning equipment. Also, the boiler has no provision for ash removal. A lance-type traveling soot-blower was mounted in the boiler floor to cover the entire length of the boiler, for blowing steam to either re-entrain deposited ash or push ash to the rear of the boiler for removal. The ash collected in the ash hopper at the rear of the boiler could be sluiced out. (This system was, however, not used in actual operation, since there was very little ash deposition in the radiative section of the boiler.)

9.1 Phase I

During the period May to June 1976, the boiler was operated for 250 hours, burning a mixture of 35 weight percent coal, 59 weight percent oil, and 6 weight percent emulsifier solution. (3/4 of 1% emulsifier and 5 1/4% water). The steam load ranged from 45,000 to 70,000 lbs. per hour, with occasional loads of 96,000 lbs. per hour. Two types of burners were tested during this period: namely steam atomized burner and air atomized burner. With both types of burners, the flame envelop was as good or better than with No. 6 oil. Although the fire appeared less brilliant with coal-oil mixture, no sparklers were noticeable. In general, the air atomized burners gave a better performance than the steam atomized burners, and both burners could be switched from coal-oil mixture to No. 6 oil, with minor air register adjustments. The only major problem associated with the steam atomized burners was the deposition of carbonacous materials on the tip of the burners. The burners had, therefore, greater tendency to plug than the air atomized burners and had to be cleaned more frequently.

Stack testing was conducted to measure NO_x, CO, and opacity over a wide range of oxygen levels. The stack had a gray smoke with 32-35% average opacity during the test. The opacity increased considerably during soot blowing periods and was unacceptable. Fly ash particulates samples were drawn and analyzed. The fly ash size was very small and almost all of the material was less than 20 microns in size. The NO_x levels increased approximately 100-150 ppm for coal-oil mixture combustion over burning No. 6 oil. This can be somewhat attributed to the higher nitrogen level in coal. Carbon monoxide levels were, however, almost the same in both cases (Table 2).

TABLE 2

Air Atomized Burner Performance

	No. 6 Oil	Coal-Oil Mixture
Steam flow rate (lb/h)	40-45,000	40-45,000
Fuel pressure (psig)	116	140
Oxygen (%)	5.2-8.0	4.1-7.6
NO (ppm)	155-198	265-328
CO (ppm)	6-33	4-25
Particulate emissions (gr/acf)	.0153-.0188	.373-.472
Opacity (%)	0-8	32-35

9.2 Phase II

During this phase, which ended April 30, 1977, a mixture containing 50 weight percent coal, 43.3 weight percent oil, 6.5 weight percent water, and 0.2 weight percent additive was prepared and burned. Tests were carried out to determine emissions, combustion conditions, and coal-oil mixture stability characteristics. The boiler fired coal-oil mixture for 494 hours at a range of loads, almost twenty percent of this time was at steaming rates over 70,000 lbs. per hour, with the highest being 100,000 lbs. per hour. As in the case with Phase I, it was observed that coal-oil mixtures burn in a manner very similar to No. 6 fuel oil. Also, it verified many of the observations that had been made earlier in regard to flame characterization, boiler performance, ash build-up, slagging and trouble-free operation of the air atomizing burners.

In this phase of the program, a new additive was used to improve the stability of coal-oil mixtures. A high pressure homogenizer was used to make an oil-additive-water emulsion. The oil-water emulsion thus obtained was mixed with pulverized coal in a Marion mixer.

During the period of the test, there was some settling of coal from the coal-oil mixture in the storage tank. This was caused mainly by high temperature of the coal-oil mixture. This affected the viscosity as well as the stability of the coal-oil mixture. This problem can, however, be alleviated by controlling the temperature of the mixture in the storage tank to below 150°F.

As in Phase I of the program, the steam atomized nozzle was installed initially. This system performed satisfactorily as the percentage of coal in the mixture was increased gradually from 10% to 40% coal. However, at 50% coal in the mixture, the nozzle plugged, and the remaining tests were carried out with air-atomized burners manufactured by Forney Engineering Company. A schematic of the burner head is given in Figure 4. In general, the air-atomized burner performed satisfactorily.

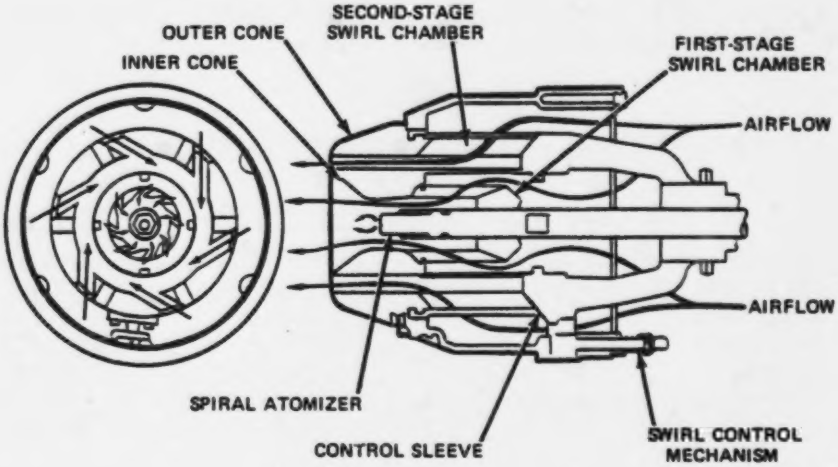

Figure 4. Burner head of air atomized Verloop burner.

10. DEMONSTRATION AT SALEM HARBOR STATION

New England Power Service Company has been awarded a cost-sharing contract by the Energy Research and Development Administration (ERDA)[7] to develop and demonstrate a coal-oil mixture as a primary fuel for generating electricity. In this program, the overall feasibility of coal-oil mixture combustion will be demonstrated in an 80 MW unit at Salem Harbor Station in Salem, Massachusetts. This boiler was originally designed for burning pulverized coal, but has been converted to and is presently burning residual oil. The specific objectives of the project are to achieve a stable combustion with coal-oil mixture

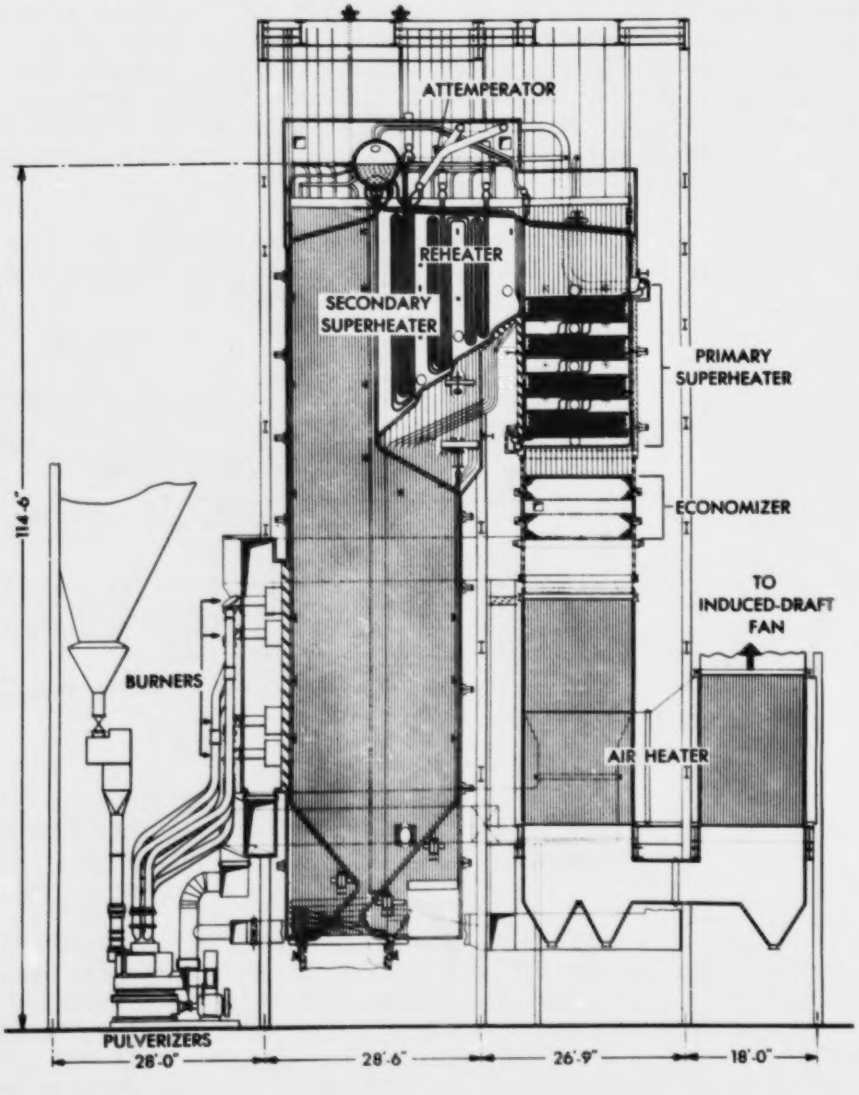
ATTEMPERATOR
REHEATER
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
ECONOMIZER
TO INDUCED-DRAFT FAN
BURNERS
AIR HEATER
114'-6"
PULVERIZERS
28'-0"
28'-6"
26'-9"
18'-0"

Figure 5. Sectional view of 80 MW Babcock and Wilcox boiler.

fuel and to demonstrate satisfactory performance of all systems and sub-systems, while meeting state and federal environmental regulations. The target concentration of coal in coal-oil mixture is 30 weight percent. Initial tests in the program are planned to be conducted with straight coal-oil mixture without the use of a chemical additive for stabilization. Concurrently, however, research and development is being conducted for development of an effective and economical stabilizing additive. Tests will be carried out with the use of this additive to determine its effect on coal-oil mixture combustion.

The test boiler (Figure 5) is a Babcock and Wilcox front-fired radiant boiler rated at a steam flow of 625,000 lbs./hour with a superheat/reheat temperature of 1,000F and a design pressure of 1,675 psi. Presently, there are 12 mechanical atomizing high pressure burners that supply a full load heat input of 880 million Btu/hr. Particulate removal from the flue gases is accomplished by means of a Research Cottrell electrostatic precipitator. The design collection efficiency of the precipitator is 97% when burning coal.

Several modifications and additions are planned for this demonstration program. Figure 6 shows a simplified flow diagram for the various systems and their interfaces. Coal will be delivered to the dock by barge and unloaded into a pile adjacent to an existing conveyor belt. Coal will be pushed into hoppers which feed the enclosed conveyor to carry coal into storage bins, inside the power plant. The bins will gradually be emptied into coal pulverizing equipment and the finely ground coal will be delivered to a storage silo to be constructed adjacent to the south wall of the power plant. The pulverized coal will then be blended with oiland pumped to an existing fuel storage tank for distribution to the burners. The existing high pressure burners and control system will be replaced with low pressure air atomized Verloop burners and the associated burner control and logic system.

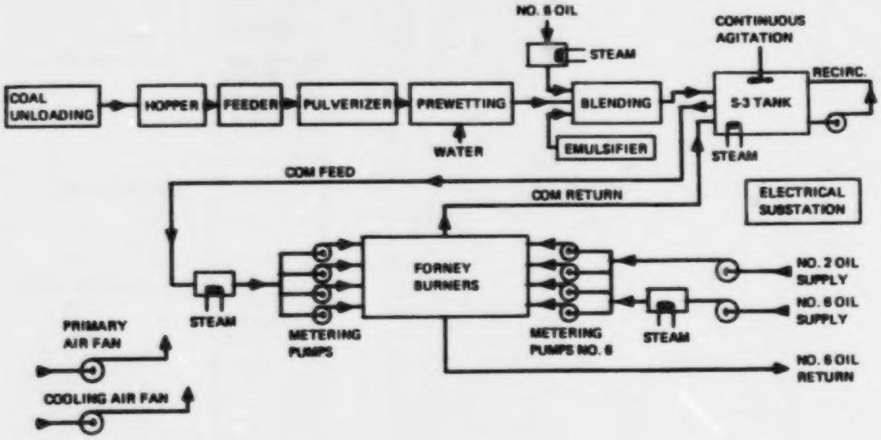
NO. 6 OIL
STEAM
CONTINUOUS AGITATION
RECIRC.
COAL UNLOADING
HOPPER
FEEDER
PULVERIZER
PREWETTING
BLENDING
S-3 TANK
WATER
EMULSIFIER
STEAM
COM FEED
COM RETURN
ELECTRICAL SUBSTATION
FORNEY BURNERS
NO. 2 OIL SUPPLY
NO. 6 OIL SUPPLY
STEAM
METERING PUMPS
METERING PUMPS NO. 6
STEAM
PRIMARY AIR FAN
NO. 6 OIL RETURN
COOLING AIR FAN

Figure 6. Simplified flow diagram of coal-oil mixture combustion demonstration.

As indicated in the schematic diagram, provision will be made for prewetting and addition of emulsifier additive to improve the stability of the coal-oil mixture, if necessary.

The test procedure is divided into two phases, each containing incremental test steps, in order to debug the various systems and to determine the effects of coal-oil mixture combustion on the boiler, precipitator, and ash system, as well as on stack emissions.

10.1 Phase I - Feasibility

The purpose of this phase is to develop combustion stability and evaluate the effects of coal-oil mixture combustion on the boiler, precipitator, auxiliary systems and stack emissions.

The initial operation will involve baseline testing of the Verloop burners on No. 6 oil. This testing will be used to debug the new system and to obtain baseline data for later comparison with the coal-oil mixture combustion results. Initially, coal-oil mixture will be burned in a single row (three burners) with remaining nine burners burning No. 6 oil. Tests will be done with mixtures of 10%, 20%, and 30% by weight coal concentration and will evaluate flame stability, emissivity, opacity, and burner performance, etc. Once the combustion stability is demonstrated, the next step in this test sequence will be a six-burner test, supplying half of the boiler heat input from coal-oil mixture fuel. At this time the effects of coal-oil mixture on the equipment, pumps, piping systems, instrumentation and burner system will be closely monitored. Potential problem areas that will be monitored are slagging in the furnace and the convection pass, plugging of the air preheater, effects of larger quantities of coal ash on the ash water recycle system and stack emissions.

10.2 Phase II - Demonstration

In this phase of the program, all twelve burners will burn coal-oil mixture, thus 100% of the boiler heat input will be supplied by the coal-oil mixture. Throughout the test period, close attention will be given to environmental aspects of burning coal-oil mixture as well as the effects of coal-oil mixture combustion on erosion, corrosion, and boiler performance will be monitored. Tests will be carried out to optimize performance of various systems and subsystems as well as to determine the efficiency of boiler and precipitators, while burning coal-oil mixture.

10.3 Schedule

It is presently anticipated to complete the installation and construction of the coal-oil mixture preparation, blending and combustion facility in the middle of 1978. The Phase I of the program is scheduled for six months duration. After the Phase I results have been evaluated, a decision will be made to proceed into Phase II of the program. It is anticipated that this phase will begin in early 1979 and run through the conclusion of the project scheduled for the end of 1979.

11. POTENTIAL BENEFITS

There are a number of potential benefits to the United States if coal-oil mixture combustion feasibility can be demonstrated. The most obvious advantage is a reduced dependency on imported oil if 30-40% of the fuel burned becomes domestically produced in the coal-oil mixture. Combustion of coal-oil mixture will, evidently, have less impact on air quality than 100% coal burning. It has potentially a wide area of application on boilers originally designed to burn coal or oil but cannot burn coal in view of changed circumstances. Although some further technical development is desirable, coal-oil mixture as a fuel has a potential for a near-term alternative for utilities and industrial boiler applications.

Furthermore, a central coal-oil mixture preparation plant can be visualized that prepares and ships a stabilized coal-oil mixture to outlying power plants. Small users could buy such fuel and presumably interchange coal-oil mixture and oil with a minimum of turn-around and expense. Large users of coal could probably justify their own preparation facilities.

ACKNOWLEDGEMENT

The author gratefully acknowledges the assistance of Mr. Andrew Brown, Jr., Project Manager, General Motors Corporation, for providing the results of the General Motors demonstration tests; and Mr. Richard M. Dunn, for his contribution related to the coal-oil mixture project at Salem Harbor Station.

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STOKERS FOR INDUSTRIAL BOILERS: ASSESSMENT OF TECHNICAL, ECONOMIC, AND ENVIRONMENTAL FACTORS

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INTRODUCTION

The firing of boilers for process steam, space heating, and on-site power generation accounts for about half of all the fuel used by American industry--nearly as much as that consumed in the generation of electricity by utilities. Coal once was the dominant fuel for such industrial boilers; it now provides only about one-quarter of their fuel.

Economic and environmental factors over the past 30 years have made coal relatively unattractive for industrial boilers. Both the capital and operating costs of coal-fired boiler installations are inherently higher than those of equivalent facilities designed for gas and/or oil firing. Thus, with the widespread availability of oil and gas in the late 1940's and early 1950's, there was a drastic decline in the demand for the industrial stoker. Only in some of the largest boiler installations could the savings resulting from the somewhat lower cost of coal offset the greater capital and operating costs. As a consequence, there has been little incentive for manufacturers to improve stoker technology through research and development. However, a resurgence of demand can be forecast for the near term in view of the fuel supply situation and possible legislative action.

Stoker-fired boilers are now at a further disadvantage with respect to environmental considerations, as their emissions of particulate and SO_2 are high in comparison to gas- and oil-fired boilers. The establishment of stringent air-pollution regulations in recent years (with national standards for large new installations and local standards for many other installations) has accentuated the economic disadvantages of stoker boilers. Costs of installing and operating the downstream control equipment that is needed to control emissions of fly ash and SO_2 for industrial boilers are relatively higher on a Btu basis than for larger utility power plants.

The potential market for stokers is dependent on many factors, some of which are difficult to assess because they involve both public

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* The author wishes to acknowledge the guidance and assistance given by Battelle staff--R. E. Barrett, D. W. Locklin, and R. B. Engdahl.

and industry acceptance of stoker firing. The industrial boiler (typically with rates steam-generating capacity between 10,000 and 500,000 pph*) is primarily utilized to generate steam for process and space heating and often is subjected to widely varying loads. Unlike the utility boiler, the industrial boiler is usually a secondary consideration in an industrial complex. The characteristics sought include:

- Low first costs
- Low maintenance
- High reliability
- Ease of operation
- Minor auxiliary equipment requirements
- Wide turndown
- Quick response.

Most of these features are more easily obtained with the oil- or gas-fired boiler. Recently, however, the availability of oil and gas has become an increasingly important factor in the selection of boilers and may outweigh all other factors if the shortage of these fuels becomes as severe as expected. Thus, the stoker-fired boiler will become more popular in the near term until coal conversion processes such as coal desulfurization, gasification, or liquefaction are commonly available or advanced coal-burning techniques such as fluidized-bed combustion reach the economically competitive stage.

CHARACTERIZATION OF STOKER TYPES

Stokers of various types are designed to mechanically feed coal uniformly onto a grate or tuyeres within a furnace, to supply combustion air to the fuel bed, and to remove ash from the zone of combustion. The development of the mechanical stoker has advanced through the years, and the modern stoker is still considered an important element in the industrial combustion of coal as well as other types of solid fuel. The modern stoker-boiler system incorporates controls to coordinate air and fuel supply with changing loads, dust-collecting equipment to minimize emissions, and, in many cases, fly-carbon return systems to increase efficiency.

Stokers are classified according to the method of feeding fuel to the furnace, namely:

- Spreader
- Underfeed
- Chain grate or traveling grate
- Vibrating grate.

The type of stoker used in a given installation depends upon

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[*] pph = pounds steam generated per hour; one lb/hr - approximately 1000 Btu/hr.

the general system design, the capacity required, and the type of fuel burned. In general, the spreader stoker is the most widely used in the capacity range of 75,000 to 400,000 pph because it responds quickly to load changes and can burn a wide range of coals. The underfeed stokers are principally utilized with small industrial boilers of less than 30,000 pph. In the intermediate range the large underfeed units, as well as the chain- and traveling-grate stokers, are being displaced by spreader and vibrating-grate stokers. A brief description of each class of stoker is given below. The major features of each are summarized in Table 1. Detailed discussions of the various stoker types can be found in the 37th and 38th editions of Steam, Its Generation and Use, published by the Babcock & Wilcox Company, New York(1).

TRENDS IN COAL FIRING AND STOKER TYPES

Recent Battelle-Columbus studies directed to the characterization of the industrial boiler population provide some insight as to trends in coal-firing methods by boiler size range. Information on the industrial boiler population and design trends was developed in a special survey of boiler manufacturers conducted jointly by Battelle and the American Boiler Manufacturer's Association (ABMA) and reported in Reference (2). These results were later refined on the basis of an analysis of recent sales data for industrial-size water-tube boilers(3).

Firing methods are boiler-size dependent. Thus, different size categories were defined as follows for the presentation of trend information:

Size Category	Size Range, 1000 pph
A	10 - 16
B	17 - 100
C	101 - 250
D	251 - 500

Smaller boilers are placed in the "commercial" class and larger boilers are considered to be "utility boilers".

Trends in Coal-Firing Capability

Figure 1 shows trends in coal-firing capability estimated for boilers in the four size categories installed in 1930, 1950, and 1970 and forecasted for 1990(3). The data apply to boilers designed to fire coal or having a capability to fire coal as a secondary fuel. This distribution is shown as a percentage of all industrial boilers. The projection for 1990 was revised by Battelle from the earlier survey on the basis of the following broad assumptions:

- Oil and gas supplies will be limited.
- Oil and gas will be utilized in smaller equipment and for high-priority uses (but not fully by mandatory allocation).
- Coal will dominate new installations in the larger sizes.

TABLE 1. CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

Stoker Type and Subclass	Typical Capacity Range, pph[a]	Maximum Burning Rate, Btu/hr-ft^2	Characteristics
Spreader			Capable of burning a wide range of coals, best ability to follow fluctuating loads, high fly-ash carryover, low load smoke
Stationary and dumping grate	20,000 to 80,000	450,000	
Traveling grate	100,000 to 400,000	750,000	
Vibrating grate	20,000 to 100,000	400,000	
Underfeed			
Single or double retort	20,000 to 30,000	400,000	Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly-ash carryover, suitable for continuous-load operation
Multiple retort	30,000 to 500,000	600,000	
Chain grate and traveling grate	20,000 to 100,000	500,000	Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
Vibrating grate	30,000 to 150,000	400,000	Low maintenance, low fly-ash carryover, capable of burning wide variety of weakly caking coals, smokeless operation over entire range

[a] pph = lb steam per hr; 1 pph ≅ 1000 Btu/hr.

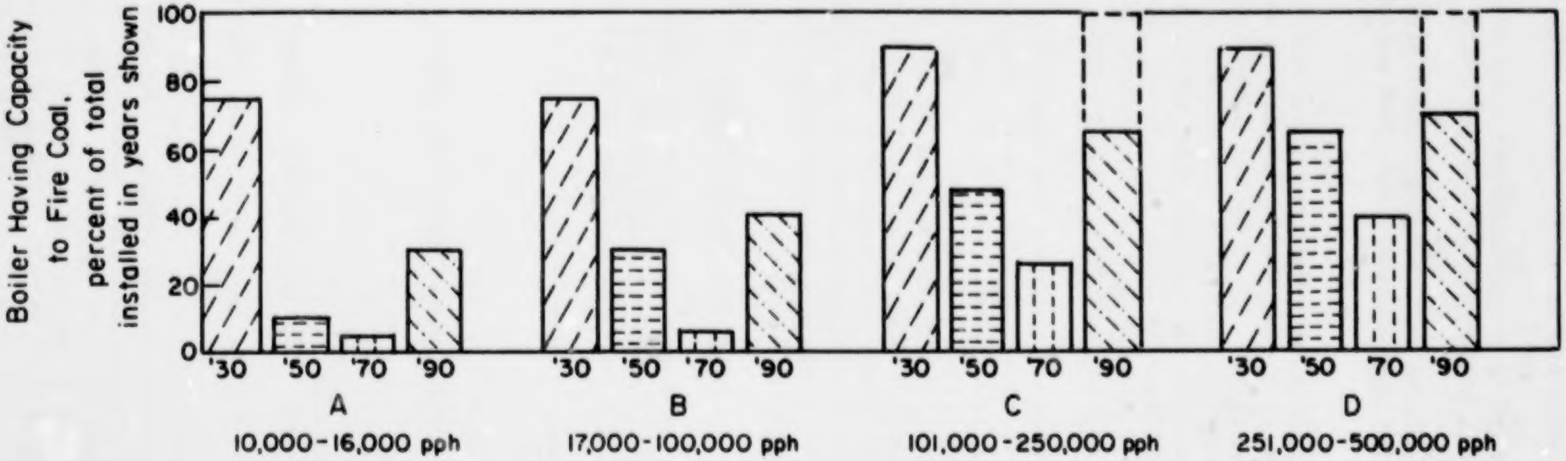

Figure 1. Estimated Percentage of all Boilers in Four Size Categories Installed in 1930, 1950, and 1970 and Forecasted for 1990 Having a Capability to Fire Coal.

- Clean liquid and gaseous fuels from coal conversion processes will not be available in large quantities by 1990.
- Firing refuse as a supplementary fuel will increase, but will not become significant in terms of percentages.

The coal projection includes the firing of chemically refined solid fuels, but does not include future synthetic liquid or gaseous fuels derived from coal.

The trends in Figure 1 indicate that coal was the dominant fuel for industrial boilers in the pre-World War II era and that most boilers had a coal-firing capability. By 1950, the number of units with a coal-firing capability dropped dramatically for boilers being installed in the smaller size categories; in the largest size category, 65 percent of the boilers had the capability. By 1970, coal firing nearly disappeared from the smaller boiler size categories, but 40 percent of the largest boilers were being installed with a capability to fire coal.

For the future, a return to the capability for direct firing of coal was forecast for new installations in the next 15 years, especially in larger sizes, where about 70 percent of the new boilers are expected to have coal-fire capability. In the event of new legislation and/or fuel priority allocations that prohibit firing gas and oil in large boilers, all new industrial boilers may be required to have a coal capability. Some large industrial companies have already made the decision to provide for a coal capability in new installations as a measure of insurance to keep manufacturing plants operating in the face of an uncertain fuels situation.

Trends in Stoker Types

Figure 2 shows trends in coal-firing methods for industrial boilers in each of the four size categories as developed in the studies cited earlier(3). Firing methods included in these data are:

- Stoker types

  Spreader
  Underfeed
  Overfeed (chain grate, traveling grate, or vibrating grate)

- Other

  Pulverized coal
  Miscellaneous (cyclone, refuse, sawdust, wood, etc.).

The following overall observations can be made from Figure 2:

- Before the introduction and commercialization of the spreader stoker in the 1930's, underfeed stokers dominated the smaller size categories and had an appreciable share of the market in the larger sizes, The overfeed types were significant in all sizes, especially larger sizes. Firing of pulverized coal was significant only in the largest sizes.

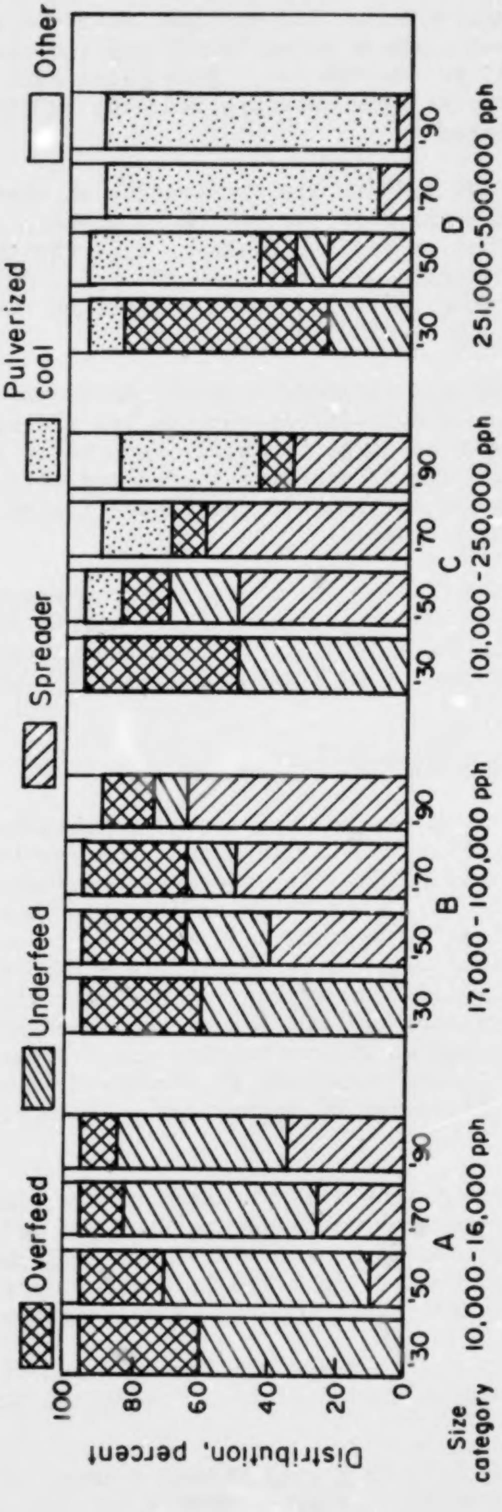

Figure 2. Estimated Breakdown by Firing Method of Solid Fuel Boilers in Four Size Categories Installed in 1930, 1950, and 1970 and Forecasted for 1990 .

- By 1950, the spreader stoker had gained a significant share of the market below 250,000 pph, mainly displacing overfeed stokers below 17,000 pph and underfeed stokers from 17 to 100,000 pph. Pulverized coal made some inroads in the size category from 101 to 250 pph during this period.

- In the 1950's and 1960's, the penetration of spreader stokers into the share of the underfeed stokers continued to the point that it was the dominant type for the range of sizes encompassing 17,000 to 250,000 pph. Pulverized-coal firing gained further, nearly dominating the market above 250,000 pph by 1970.

- For the near future, spreader stokers can be expected to continue to gain popularity in the smaller sizes, with underfeed stokers holding the major share below 17,000 pph. Spreader stokers can be expected to decline slightly in the market share above 100,000 pph, where firing of pulverized coal is strongest.

It should be noted that introduction and successful commercialization of the fluidized-bed combustion concept to industrial boilers could displace the more conventional firing methods by 1990, and, thus, significantly alter the distributions forecasted in Figure 2, especially above 100,000 pph.

EMISSIONS FROM STOKER-FIRED BOILERS

Table 2 summarizes the emission factors* established by EPA as averages for fossil-fuel combustion(4). As noted, the particulate and sulfur dioxide emissions are significantly higher for combustion of coal than for fuel oil or natural gas, especially considering that coal can have an ash content as high as 20 percent and a sulfur content as high as 4 percent. Also, whereas fuel oil can be desulfurized before firing, there are currently no commercially viable methods for mechanically treating or preparing coal to reduce emissions of SO_2 (other than washing, which cannot remove organically combined sulfur or fine dispersions of pyritic sulfur). Consequently, to reduce emissions from coal-fired combustion sources necessitates the utilization of downstream emission-control equipment.

Because available emission data for stokers are limited, there are no computational procedures for establishing specific relations among emission levels, stoker type and design, boiler load, coal characteristics, and coal size. The emission factors in Table 2, however, are representative of a broad grouping of equipment types and can serve as guidelines.

Generally, stokers that agitate the fuel bed and disturb the ash increase the fly ash loading in the stack. Generally, this agitation

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*The emission factor as used here is a statistical average of the rate at which a pollutant is released to the atmosphere per unit of fuel consumed(4).

TABLE 2. EMISSION FACTORS FOR FOSSIL-FUEL COMBUSTION WITHOUT CONTROL EQUIPMENT(4)

Fuel and Type of Combustion Unit	Emission Factor, lb/10^6 Btu of fuel consumed				
	Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides
Coal					
Power plant, pulverized					
General	0.64 A[a]	1.25 S[b]	0.04	0.012	0.72
Cyclone burner	0.08 A	1.52 S	0.04	0.012	2.2
Commercial and industrial stoker					
Spreader	0.52 A	1.52 S	0.08	0.04	0.60
Others	0.20 A	1.52 S	0.08	0.04	0.60
Residual oil					
Power plant (also includes distillate oil-fired plant boilers	0.053	1.04 S	0.02	0.013	0.7
Commercial and industrial	0.153	1.04 S	0.026	0.02	0.27 to 0.54
Distillate oil: commercial and industrial	0.01	0.95	0.026	0.02	0.27 to 0.54
Natural gas					
Power plant	0.015	0.0006	0.017	0.001	0.600
Commercial and industrial	0.18	0.0006	0.017	0.003	0.120 to 0.230

(a) The letter "A" indicates that the weight percentage of ash in the coal should be multiplied by the value given. Example: If the factor is 0.64 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 0.64, or 6.4 lb/10^6 Btu (about 160 lb/ton).

(b) "S" equals the sulfur content [see footnote (a) above] in weight percent.

is intermittent, as is the case for dumping-grate or vibrating-grate stokers. The spreader stoker, however, burns up to 50 percent of the coal in suspension and, thus, has the highest fly-ash loading of all types of stokers.

Sulfur oxide emissions from stokers, as well as from all fossil-fuel combustion equipment, are directly related to the sulfur content of the fuel. Presently, there are no combustor designs or equipment operational modifications that can reduce these emissions except for the still commercially unproven fluidized-bed combustors. In addition, unlike the utility power plant, the economics and the geographical location of stoker-fired commercial and industrial plants usually are unfavorable for utilizing tall stacks to reduce ambient SO_2 to acceptable levels.

Emissions of carbon monoxide, unburned hydrocarbons and nitrogen oxides from stoker boilers generally are within air-pollution standards, provided that the units are operating properly.

COMPETITIVE SITUATION IN INDUSTRIAL FUELS

Figure 3 provides a comparison of steam-generation costs for various fuels on the basis of a load factor of 0.30, a boiler efficiency of 0.80, and an annualization rate of 16.7 percent. The estimated costs include both capital and operating expenses. It is apparent from the example shown that the stoker boiler is economically attractive when the cost differential between stoker coal and other fuels is greater than $\$1/10^6$ Btu. For example, if stoker coal costs $\$1/10^6$ Btu (approximately \$26/ton), steam-generation costs would be approximately $\$3/10^3$ lb of steam. In an oil or gas boiler, the fuel costs would have to be no higher than $\$2/10^6$ Btu to generate steam at $\$3/10^3$ lb. In the past, the cost of all industrial fuels was much less than $\$1/10^6$ Btu and cost differentials were about $\$0.50/10^6$ Btu between fuels.

Figure 3 also indicates the steam costs from a stoker boiler equipped with SO_2 scrubbing equipment. Because of the relatively high costs estimated, it is unlikely that SO_2 scrubbing will be utilized with medium-size industrial boilers (unless dictated by Government regulation).

ECONOMICS OF INDUSTRIAL-STOKER OPERATION

The economics of industrial utilization of stoker coal are difficult to assess for reasons that include:

- Uncertainty in the availability and price of all fuels
- Wide variation in the cost and quality of stoker-boiler systems
- Unavailability of extensive operational cost-breakdown information
- Unavailability of proven SO_2-control technology.

Delineation of the economic situation with some degree of confidence would have required an effort that was beyond the scope of this paper. As a consequence, the analysis that was developed and is given below should be regarded only as a guideline and for making relative comparisons between types of fuel.

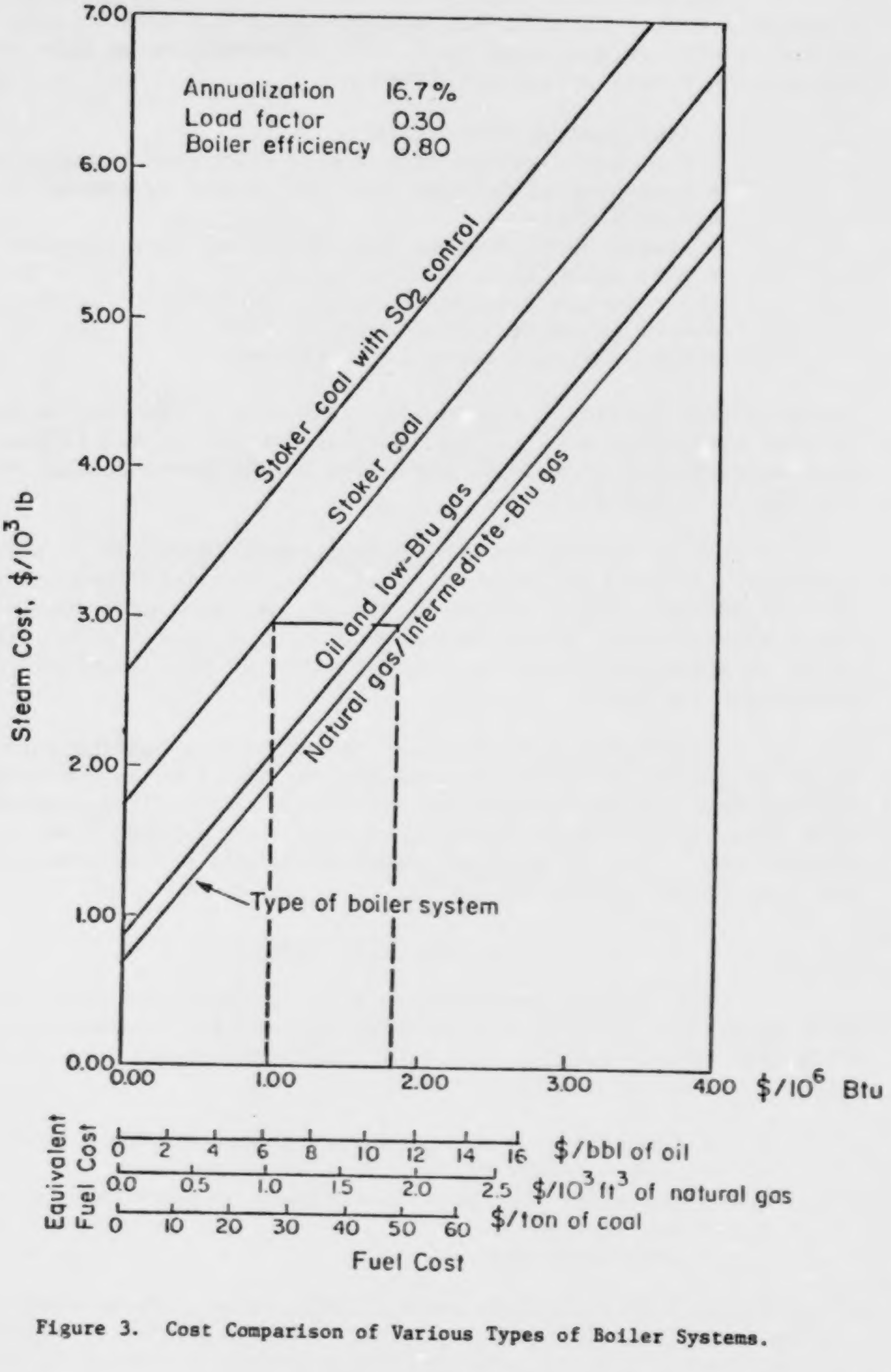

Figure 3. Cost Comparison of Various Types of Boiler Systems.

Capital Costs

Because coal-fired stoker boilers are more complex, the capital costs of a stoker-fired boiler are significantly greater than those of either an oil- or gas-fired unit. In comparison to an oil- or gas-fired boiler, the stoker boiler requires:

- Ash-handling facilities
- Fly-carbon reinjection system (for some spreader stokers)
- Very-high-efficiency dust-collection equipment
- Soot blowers
- Larger flow passages and additional heat-transfer surfaces
- More extensive combustion controls
- More extensive fuel-handling and storage facilities
- More extensive field erection work
- More physical space for facilities.

These factors result in the capital cost of a stoker boiler being from two to four times that of a packaged boiler for oil or gas firing. Capital-cost differential will vary, depending on equipment design, manufacturer, and type of installation.

As an example of the economic attractiveness of gas- or oil-fired equipment, one manufacturer estimated that the delivered and erected cost of a 75,000-pph boiler was $6/pph for an oil/gas packaged unit and $20/pph for a stoker boiler (with dust control). The stoker alone can account for up to 20 percent of this cost with another 20 percent attributed to dust-collection equipment.

With the other costs associated with a heating plant, the capital costs of placing a boiler on line are estimated to be approximately $10/pph for oil/gas and $25/pph for stoker coal. (These numbers are based upon information from a manufacturer and were derived from one set of assumptions.) SO_2-cleanup equipment would add an additional $12/pph to the cost of the stoker boiler(5).

Operating Costs

The average operating costs of boilers are difficult to determine because of differing accounting procedures. However, in comparison with oil- or gas-fired units, stoker boilers clearly have higher operating costs. These can be attributed to:

- More frequent and closer attention required by operator
- Higher degree of boiler-operator skill
- Additional mechanical equipment to service
- Ash removal
- Fuel handling.

In addition, the fuel costs must be considered. These costs vary from region to region and have become difficult to predict. A check on the current fuel prices in Columbus, Ohio, indicates little difference among the energy costs of stoker coal and natural gas, while fuel oil costs about 50 percent more.

CONVERSION TO STOKER FIRING - FACTORS TO CONSIDER

Stoker fuel can be a viable fuel for meeting industry's demand for energy. However, as alluded to earlier, certain factors must be considered in the design and operation of the overall system that include:

- Space
  - boiler and auxiliary equipment
  - coal handling and ash disposal systems
  - pollution control equipment

- Costs
  - capital
  - operating

- Operation
  - operator skill
  - high maintenance.

Generally, a boiler that has not been designed for coal firing cannot be converted. Additionally, if a new coal-fired boiler is installed, a substantial amount of space is required for the new and larger boiler and all the ancillary equipment associated with it. Also, even with the higher cost of gas and oil, stoker firing presently in many instances cannot be justified on economics alone.

BCL Stoker Conversion

During 1976, Battelle's Columbus Laboratories (BCL) converted one of their 600-hp (25,000 pph steam) oil/gas boilers, originally designed for coal firing, to stoker (spreader) firing. These boilers were originally installed with oil or gas firing, but the units were designed and assembled with conversion to coal firing in mind. The decision to convert to coal was not primarily one of economics, but one rather to assure continued operation of the steam plant. The overall cost of converting one of the existing boilers was $800,000. About half the cost was associated with the boiler modification and stoker installation while the remaining half with the coal and ash handling equipment, pollution controls, and engineering design.

The conversion essentially doubles the space of the steam plant facility. Ash and coal silos, above and below ground bunkers, and bucket elevators were located adjacent to the steam plant, while the two-stage dust collector, forced and induced draft fans, and 18-ton coal hopper were located within the building.

With the conversion, higher maintenance is required. Instead of the fuel being supplied to the boiler through a pipe, coal is delivered through a system of bucket elevators, screw feeds, and conveyors. As expected, several small mechanical difficulties have occurred time to time. Likewise, operational problems, such as low-load smoke and excessive slagging with low ash-fusion temperature coals, were experienced. These and other problems have been minimized by proper coal selection and stoker operation.

CONCLUSIONS

It appears that the future market for stoker boilers and the corresponding demand for stoker coal will be dependent on factors that include:

- National policy decisions that affect the availability of fuels
- Local and national SO_2 regulations
- Development of suitable SO_2 control systems (either in-furnace control systems or stack-gas scrubber systems)
- Availability of clean coal-derived fuels or commercialization of fluidized-bed combustion systems with sulfur removal.

The stoker market appears promising for the next 5 to 10 years and perhaps longer, particularly for the large stokers. The market for the small- and medium-sized stoker is less definitive, but sales of medium-sized industrial stokers will probably increase over the essentially negligible levels of recent years. Although stokers firing high-sulfur coal emit SO_2 at levels above those specified by many state source standards, it is anticipated that some relaxation of these standards may occur, provided that the local primary ambient standards are being met. It is also possible that economic and practical SO_2 stack-gas cleanup systems will be developed, but these systems appear to have many problems.

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5. "Initial Operating Experiences with Dual-Alkali SO_2 Removal System", Presented at the EPA Symposium on Flue-Gas Desulfurization, Atlanta, November 4, 1974.

INITIAL OPERATION OF THE 30 MW_e RIVESVILLE MULTICELL FLUIDIZED BED STEAM GENERATION SYSTEM

by

Robert L. Gamble and Newton G. Wattis
Foster Wheeler Energy Corporation

ABSTRACT

The world's largest fluidized bed steam generator located at Rivesville, West Virginia is currently undergoing initial operation. This unit is designed to generate 37.8 kg/s (300,000 lb/hr) equivalent to 30 MW_e of superheated steam while firing coal in a fluidized bed of limestone. Coal was first fired in this unit in December, 1976 and start-up operation is progressing.

INTRODUCTION

Coal is presently our nation's most abundant energy source. Current environmental regulations require that coal be mined and consumed in an environmentally acceptable manner. The majority of the energy consumption in this country is east of the Mississippi river and the majority of the coal resources east of the Mississippi contain quantities of sulfur which prohibit direct combustion without means for controlling emissions within current limits. Direct combustion of coal in fluidized beds of limestone has shown to be a near term practical method for energy conversion with high sulfur coal.

The fluidized bed steam generation system located at the Monongahela Power Company, Rivesville, West Virginia plant has been sponsored by the United States Energy Research and Development Administration (ERDA). The Rivesville system has been designed by Pope, Evans and Robbins, Inc. and includes a multicell fluidized bed steam generator designed and erected by Foster Wheeler Energy Corporation. The entire system has been retrofit into an existing power plant and steam produced from this system will be used to drive an existing turbine-generator and generate approximately 30 MW_e of electric power. The system installed at Rivesville is designed to generate 37.8 kg/s (300,000 lb/hr) of superheated steam and is several times larger than any other fluidized bed steam generation system in the world.

Following the initial start-up operation, de-bugging of the systems at the Rivesville plant and installation of test instrumentation, a test program of approximately one year duration will commence. Successful operation of this unit will be a major step toward the commercialization of both industrial and utility fluidized bed steam generators which will be capable of directly firing low grade and high sulfur coals within present environmental emission limits.

FLUIDIZED BED COMBUSTION

A fluidized bed is a bed of granular particles supported by a non-sifting grid through which an upward flow of air or gas is passed with sufficient velocity to lift and float the granular particles. As the velocity of fluidizing gas is increased, the bed will expand and bubbles will form similar to a pot of boiling water, and in this state the fluidized bed exhibits the properties of a liquid. Figure 1 schematically represents a fluidized bed steam generator. In the case of a fluidized bed steam generator firing high sulfur coal, the fluidized bed particles are normally crushed limestone. Crushed coal is injected into the fluidized bed of limestone and burns, converting the fuel bound sulfur to sulfur dioxide (SO_2). If the bed is designed and operated to maintain a bed temperature of 815-870C (1500-1600F), the SO_2 released from the coal combustion will be chemically absorbed by the limestone bed material. Tests have indicated that SO_2 emissions can be controlled for virtually all United States coals by maintaining active limestone bed material within the fluidized bed. This is done by feeding raw limestone with the coal and regulating the bed material inventory by a gravity drain system which withdraws spent material and large coal ash particles.

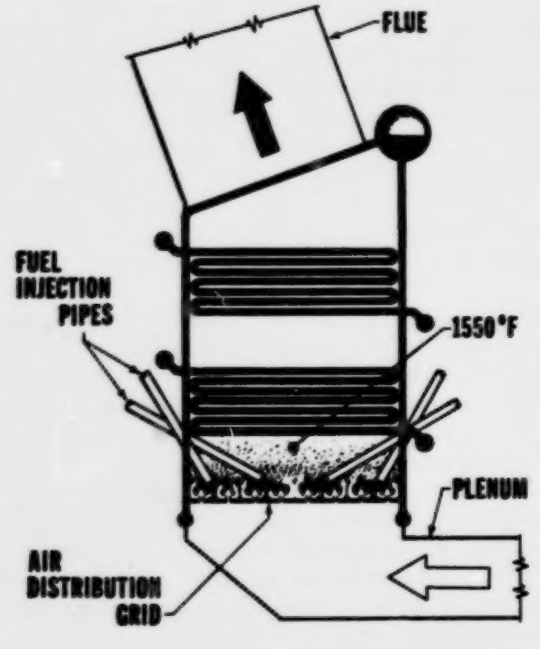

Figure 1. Fluidized Bed Steam Generator.

Due to the relatively low operating temperature of the fluidized bed, NO_x emissions are inherently low and no special systems are required for control of NO_x emission to meet the current emissions limit. Particulate emissions can be controlled conventionally with either electrostatic precipitators or baghouse filters.

Many thousands of hours have been logged in pilot unit operation at the Pope, Evans and Robbins, Inc., Alexandria, Virginia facility, the Foster Wheeler Energy Corporation test unit at Livingston, New Jersey and other pilot units throughout the United States and overseas.

RIVESVILLE UNIT DESIGN

The Rivesville systems design can be divided into four (4) primary areas which include (a) the air and gas systems, (b) the water and steam systems, (c) the fuel and limestone injection systems and (d) the bed material recycle system. A description of each of these systems follows:

a. Air and Gas Systems - The air and gas systems are typical of that found in a utility power plant steam generating system. Air is supplied by a forced draft fan through a regenerative air preheater and the flow rate is regulated to each section of the boiler by individual air regulating dampers. The air passes through the air distribution grid and the fluidized bed coal combustion zone, and from this point flue gas flows over convection type heat transfer surface and to cyclone particle separators, through a hot (385C, 730F) electrostatic precipitator, and on to the gas side of the regenerative air preheater and induced draft fan at the inlet of an exhaust stack.

b. Water and Steam Circuit - A schematic of the steam generator circuit is indicated in Figure 2. Feedwater from the existing plant feedwater system enters the economizer inlet and flows in series

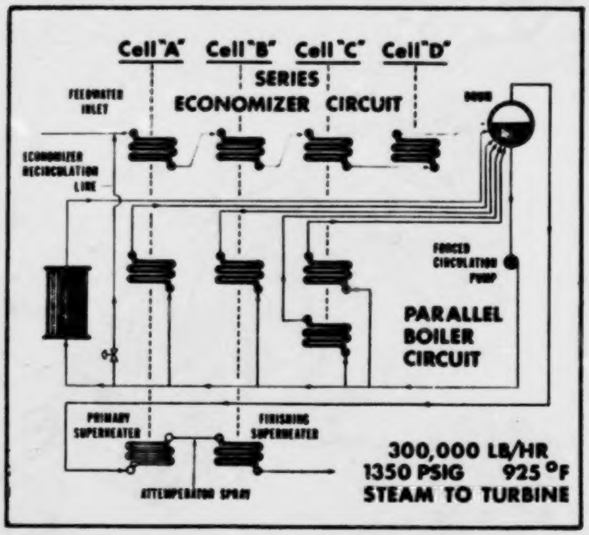
Cell "A"
Cell "B"
Cell "C"
Cell "D"
SERIES
ECONOMIZER CIRCUIT
FEEDWATER INLET
DRUM
ECONOMIZER RECIRCULATION LINE
FORCED CIRCULATION PUMP
PARALLEL BOILER CIRCUIT
PRIMARY SUPERHEATER
FINISHING SUPERHEATER
ATTEMPERATOR SPRAY
300,000 LB/HR
1350 PSIG 925 °F
STEAM TO TURBINE

Figure 2. Demonstration Unit Circuit Schematic.

through four (4) economizer sections in each of four (4) independent boiler cells. Feedwater enters the drum and flows through the downcomers to two (2) forced circulation pumps as seen in Figure 3. The forced circulation pumps provide the head required to maintain the proper mass flow rate in the five (5) parallel boiler circuits. The boiler circuits consist of four (4) horizontal tube boiler banks and vertical tubes which form the boiler enclosure walls and cell partition walls. A steam water mixture exits these boiler circuits to the steam drum, and dried saturated steam flows from the drum through a primary superheater and subsequently through a finishing superheater. An attemporator spray station is located between the two (2) superheaters for final steam temperature trim. Steam leaving the finishing superheater is routed to the existing steam turbine where it enters at 9 MPa (1300 psig) and 495C (925F).

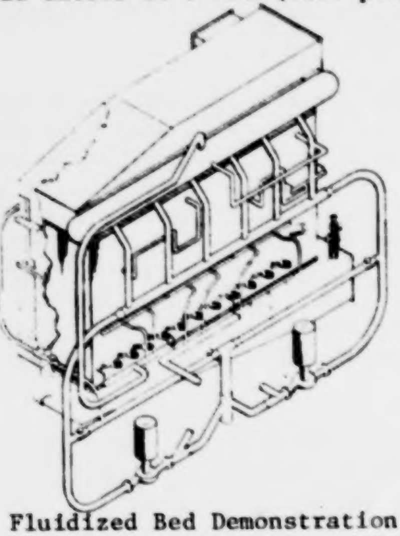

Figure 3. Multicell Fluidized Bed Demonstration Steam Generator Installed at Monongahela Power Co., Rivesville, WV, Plant.

The arrangement of the heat exchange surface indicated in the circuit schematic (Figure 2) is shown on Figure 4.

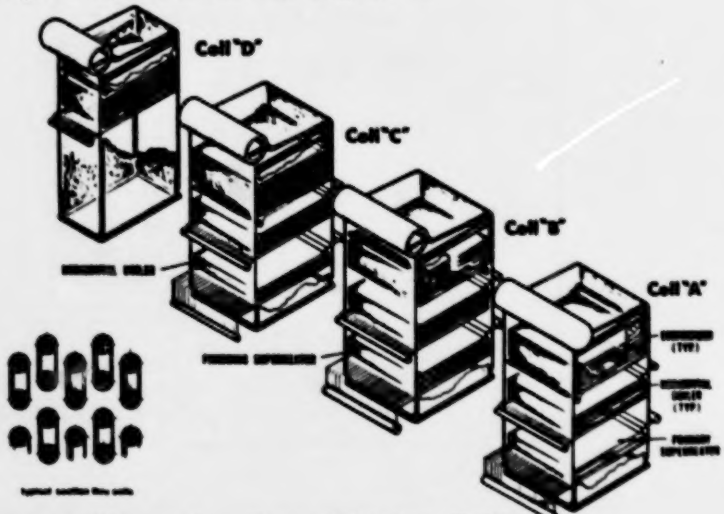

Figure 4. Demonstration Unit.

c. Fuel and Limestone Injection - Crushed limestone is received at the plant in pneumatic discharge trucks and blown into storage bunkers above the steam generator as indicated in Figure 5. Coal is either received at the plant in a crushed and dried state and loaded into the storage bunkers with the plant conveyor systems or is received as run of mine and is crushed and dried in the plant systems prior to loading in the storage bunker. A coal/limestone mix is regulated to each fluidized bed cell with rotary flow control feeders at the outlet of each of the bunkers. The coal and limestone mix into a common pipe as they fall by gravity to a rotary air lock. The rotary air lock prevents back flow of air from the slightly pressurized vibrating distributors, each of whcih distribute the coal/limestone mixture to eight (8) outlets. The vibrating distributor is pressurized to approximately 14 kPa (2 psig) with air which pneumatically carries the coal/limestone mixture through downward sloping injection pipes into the lower section of the fluidized bed. The Rivesville unit contains seven (7) coal/limestone injection systems, two (2) of which are indicated on Figure 5.

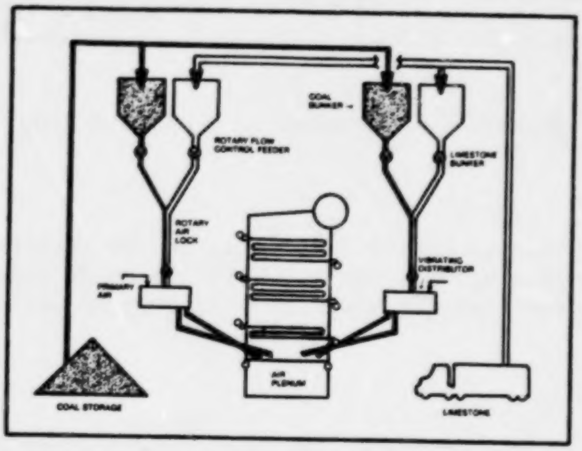

Figure 5. Fluidized Bed Fuel Injection System.

Cells A, B and C (refer to Figure 4) each receive coal and limestone from two (2) sides and Cell D, which is the smallest cell, receives coal and limestone through the single end wall. The Rivesville system uses limestone crushed to -3.2 mm (-1/8 inch) and coal crushed to -12.7 mm (-1/2 inch).

d. Bed Material Recycle System - The bed material recycle system is used to control the bed material size and inventory in each cell. Bed material is extracted from each cell through a gravity drain and the flow is regulated onto a common vibrating conveyor as indicated in Figure 6. Bed material from the common vibrating conveyor may be removed from the system by opening the bypass or may flow through a classifier which moves oversize bed material and maintains properly sized bed material for recycle back to each of the cells. Bed material to be removed from the system passes through an indirect solids cooler and is discharged to a pneumatic system for disposal. The properly sized bed material is pneumatically carried up to a bed material storage tank which contains

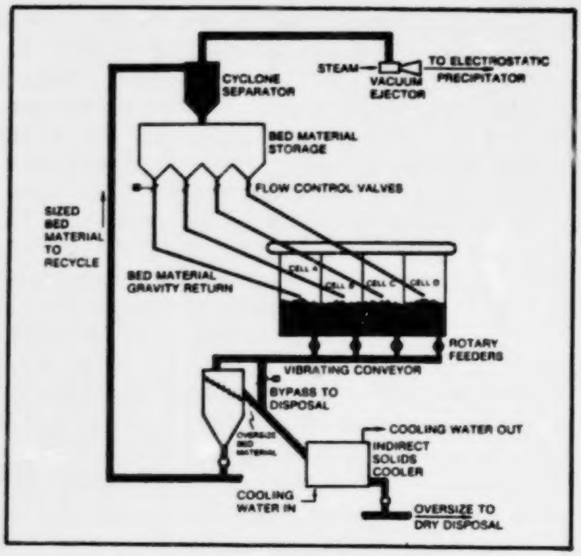
CYCLONE SEPARATOR
STEAM
VACUUM EJECTOR
TO ELECTROSTATIC PRECIPITATOR
BED MATERIAL STORAGE
FLOW CONTROL VALVES
SIZED BED MATERIAL TO RECYCLE
BED MATERIAL GRAVITY RETURN
CELL A
CELL B
CELL C
CELL D
ROTARY FEEDERS
VIBRATING CONVEYOR
BYPASS TO DISPOSAL
OVERSIZE BED MATERIAL
COOLING WATER OUT
INDIRECT SOLIDS COOLER
COOLING WATER IN
OVERSIZE TO DRY DISPOSAL

Figure 6. Bed Material Recycle System.

multiple outlets so that bed material can be returned to each of the four (4) steam generator cells. This system is designed to handle hot bed material leaving the fluidized beds at up to 1093C (2000F).

INITIAL OPERATION

During the last three (3) months of 1976, checkout and initial cold mode operation of most of the Rivesville facility systems took place.

Coal was first ignited in the D cell of the fluidized bed steam generator on December 7, 1976 with the fluidized bed temperature reaching a maximum of approximately 790C (1450F) for a short period of time due to insufficient fuel flow into the bed. Following several other short coal firing periods at the early end of the operations learning curve, coal fires were established and maintained for 33 hours on December 22 and 23, 1976. During this time bed temperature was controlled at an average of 79C (1450F) and all systems performed well. The bed temperature was easily controlled and responded well to changes in coal feed rate. Coal firing rate was approximately 10% of the steam generator full load and a drum pressure of 8.275 MPa (1200 psig) was maintained while generating saturated steam at approximately 5 kg/s (40,000 lb/hr). During this coal firing operation, firing was maintained without any ignition assistance. Figure 7 indicates the operating conditions during this thirty three (33) hour run at the end of which the unit was shut down for a scheduled outage.

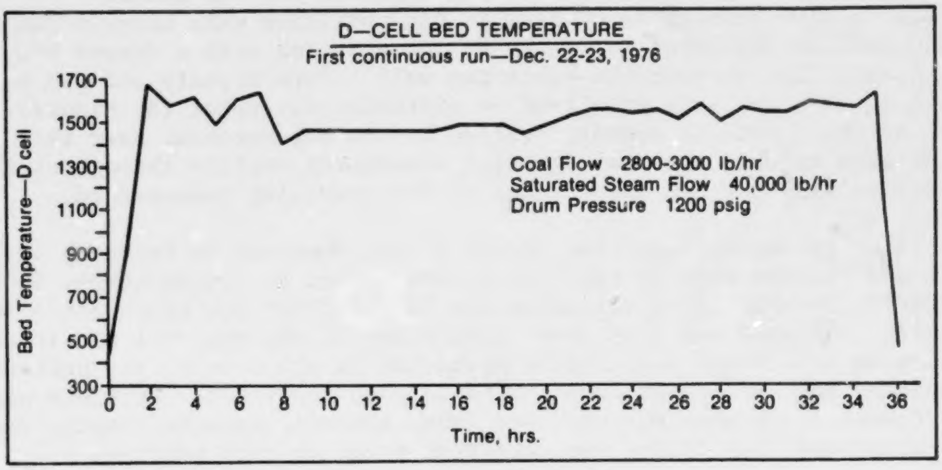

Figure 7. D-Cell Bed Temperature First Continuous Run December 22-23, 1976.

The coal handling system is designed to handle a maximum of 5% moisture coal. During January 1977 a shipment of wet coal caused operating difficulties and resulted in only intermittent coal firing operation.

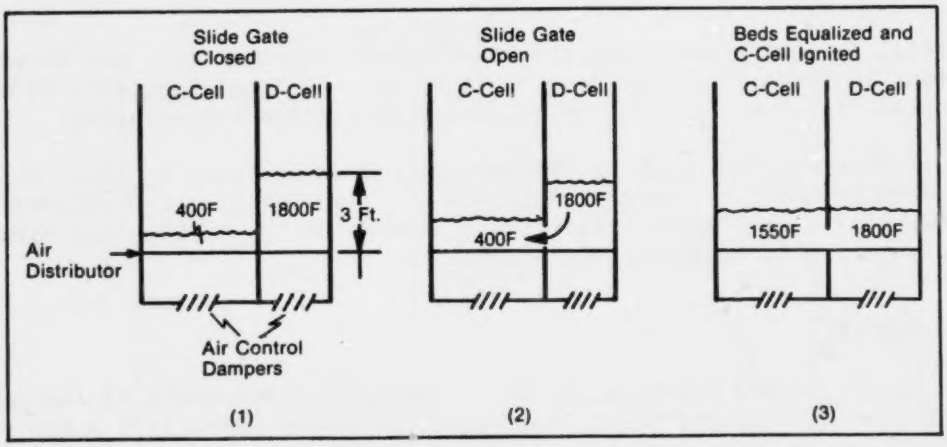
Slide Gate Closed
C-Cell
D-Cell
400F
1800F
3 Ft.
Air Distributor
Air Control Dampers
(1)
Slide Gate Open
C-Cell
D-Cell
1800F
400F
(2)
Beds Equalized and C-Cell Ignited
C-Cell
D-Cell
1550F
1800F
(3)

Figure 8. Ignition of the C-Cell.

Ignition of the C cell is achieved by allowing hot bed material in the D cell to flow through an opening in the partition wall between the D and C cell as indicated on Figure 8. By starting with a deeper bed in the D cell flow through the partition wall occurs rapidly and the bed depth in each cell are equalized in approximately three (3) minutes. Coal in the C cell is rapidly ignited by the hot material near the slide gate opening and coal ignition propagates rapidly throughout the C cell raising the bed temperature to its operating temperature.

The first successful ignition of the C cell occurred on February 10, 1977 and temperatures in the C cell were raised to approximately 870C (1600F). Shortly after obtaining the 870C (1600F) bed temperature in C cell, coal feed was lost, most likely due to the wet coal conditions. Following this short coal firing operation in the C cell, the unit was inspected and the boiler found to be in good condition. Problems with the forced draft and induced draft fans, however, required repair and no subsequent coal firing was attempted prior to this writing.

TEST PLAN

Following additional start-up efforts and upon achieving the ability to operate the remaining boiler cells, test instrumentation will be installed at the Rivesville facility and a one (1) year test program will be initiated. This test program will include determination of heat and material balances at various operating loads and a 3,000 hour continuous operation run. Installation of the test instrumentation should take place during the third quarter of 1977.

SUMMARY

Initial operation has shown that stable combustion of coal can be maintained in large fluidized beds of limestone. As coal feed rate is controlled, bed temperatures can be easily maintained and adjusted.

As of this writing, only preliminary operation has been achieved at the Rivesville facility; however, results of this operation are encouraging and indicate that upon coordinated operation of the systems the Rivesville unit should operate satisfactorily.

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DEVELOPMENT OF AN EFFICIENT SOLIDS FUEL BURNER

by

Norman A. Lyshkow
Combustion Equipment Associates, Inc.

INTRODUCTION

Much interest has been directed to the development of solids burners for use in various chemical processes. The compatibility of the heat source with the particular requirements of the process necessitates detailed study of the chemical system.

The emissions of the heat source must be analyzed in order to predict their probable effect on the product. In certain cases, emission effect is minimal; however, in the largest number of cases, solids burners are sought to replace oil and gas in stringent processes.

In addition to melt applications, the requirements of these processes vary from drying to supplying thermal energy for chemical reactions in rotary kilns. Coal use has been limited due to product contamination. The development of a combustor capable of providing a "Clean Flame" for such applications has required a thorough study in both the physical and chemical processes of solid fuel combustion. Removal of fly ash within the combustor, while providing the necessary temperature for efficient combustion, directed development efforts to a slagging type burner. As fly ash capture efficiency requirements generally vary with the process, the slagging type burner allows for the most efficient capture of fly ash as well as a practical method of ash removal. The use of a wet wall combustor also simplifies the mathematical analysis of the system.

Efficiencies in excess of ninety percent are required in many processes; theoretical efficiencies greater than 99% are predicted with pulverized coal. Extensions of the model combustor with the construction of new test combustors are planned. To date, particle efficiencies have exceeded 95%, while the possibility exists for coal combustion with particle emission levels below .1 lb/MBTU.

The design also permits such efficiencies at combustor pressures of less than two inches of water. Computer analyses have determined dimensions of burners from 1 million to 160 million BTU, with larger sizes practical.

Key to the use of solid fuels is an efficient combustor, capable of utilizing low quality, high ash fuels. The use of such fuels requires a method for qualifying them and predicting their combustion characteristics in a real system.

The need for these predictions and descriptions has promoted the development of a computer model sufficiently complex to simulate the combustion requirements and processes of fuel. The model input must be the most complete fuel description, thus necessitating the development of specialized instrumentation and procedures.

This information development must then be described in a series of equations. These equations must compensate for the variable system conditions. Initially, the equations were of the most simple type. Further expansions were tested in a model combustor to predict their accuracy.

Key to the prediction of accuracy was both carbon and particulate emission. Emission testing by EPA methods and the use of an Anderson impactor provided this correlation. The computer model devised has expanded to approximately six hundred lines with many simultaneous iteration loops. The pitfall of such a complex model is the necessity to continually maintain relevance. The complexity of solids combustion, a dynamic situation, cannot be simply described. The only constant criteria of such a model can be its prediction of accurately sized burners which meet the requirements of a successful system.

FUEL ANALYSIS

Elemental and proximate analyses are utilized in the model. In addition, a special device was constructed to ignite material under intense radiation and determine ignition time. The device was constructed to eliminate convection and conduction effects during irradiation. Other devices were constructed to determine emissivity and envelope specific gravity. Particle size analysis was performed and a technique developed to determine effective particle thickness. Ash fusion temperatures were determined to fix the temperature requirements of the combustor.

PROGRAM DEVELOPMENT

The motion and travel of a mathematically generated system of particles to predict their interactions was developed, and includes the following procedures:

(1) Continuous analysis of changing characteristics during the ignition-combustion cycle is determined for the particles. The burner is also analyzed by sector to determine energy balance of each sector.

(2) Centrifugal Force--drag force determinations--are utilized to predict particle impaction points.

Since a path of movement for each group of particles is simulated, a mathematical technique is utilized to determine the radius of curvature and centrifugal force which predicts the reasonable particle cut of the combustor. Tests using an Anderson impactor have found the combustor to be in close correlation with the mathematical simulation. The model was then directed to determine a flow field optimal for a given system of particles. The flow analysis on levels of predicted turbulence. In later studies of spectral emission, this assumption was reasonably verified.

FIELD STUDIES

A number of combustors designed by the computer model have been constructed and tested using a wide variety of solid fuels. Burners have been constructed from 3 million BTU's to 40 million BTU's. A schematic of the combustor (Figure 1) is presented. The unit is basically a cyclone-type burner. The burner is sized by the appropriate input data (Figure 2) which generates the dimensions, flow, and volume considerations for a particulate fuel at the desired combustion rate.

The output data is developed from the fuel characterization (Figure 3) by the computer model.

A burner is then constructed to the dimensions provided by the model and operated at the test facility which consists of a large water-filled chamber with a steam vent, droplet extractor, circulators and measuring means to determine water addition. In addition to the performance of material and heat balances, the test burner allows gaseous and particulate testing.

Thermocouples are located throughout the system and in the chamber gas effluent. Particulate is collected in the chamber and at the stack sampling point. Data is then analyzed to determine correlation with mathematical representations (Figure 4).

Chemical data on emissions and slag has been collected (Figure 5). Further studies in emission are planned.

To date, low NO_x values have been found to exist. In addition, concentration of sulfur in the slag has been observed and will be studied in more detail.

SUMMARY

Continuous development in mathematical representations, prototype construction, and materials of construction is underway on this project. The success of the burner design utilizing fuels as high as 35% ash and BTU contents as low as 5,500 with resultant particulate emissions as low as .34 lb/mm BTU illustrate the possibilities for utilization of the design during the present energy situation.

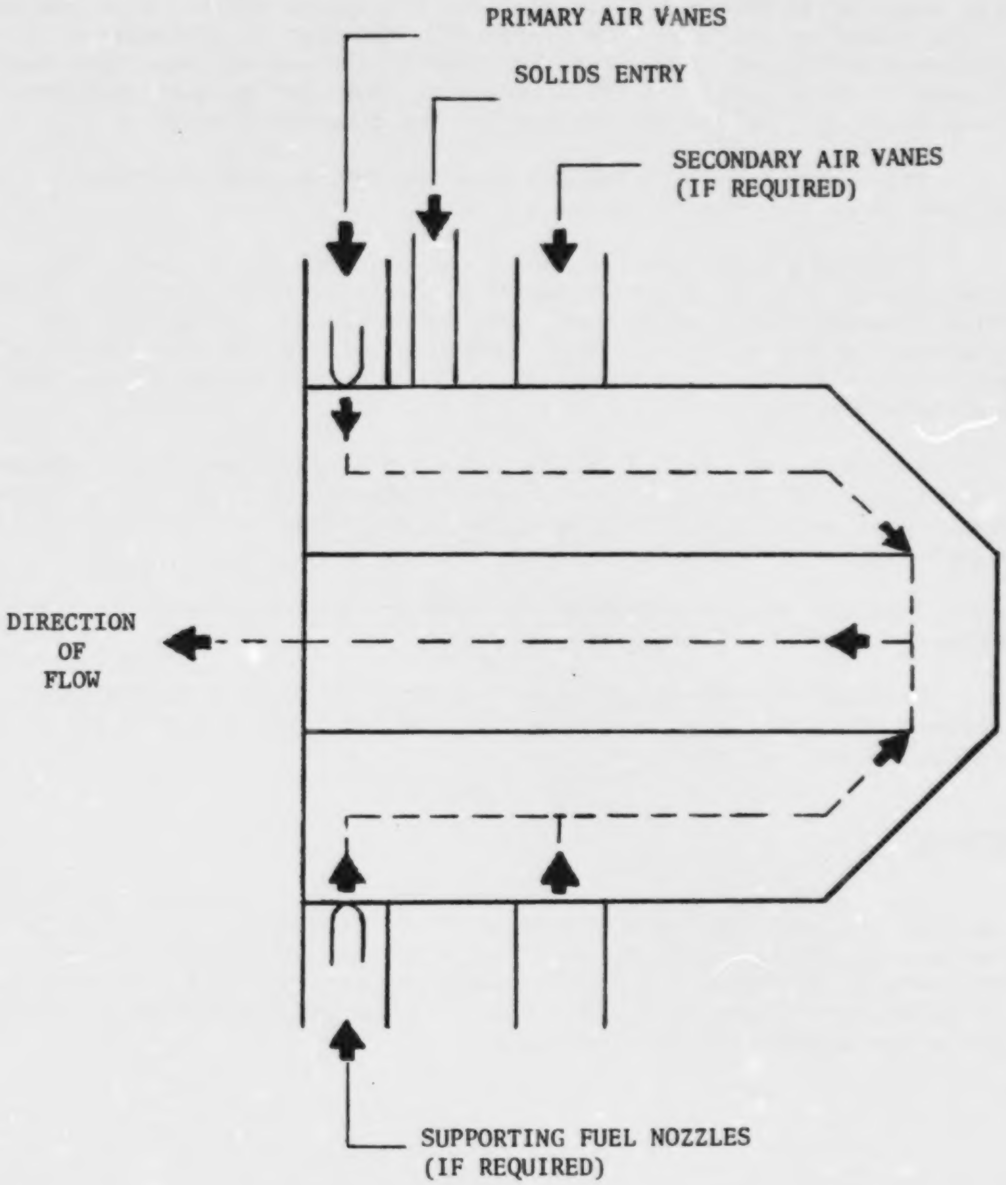
PRIMARY AIR VANES
SOLIDS ENTRY
SECONDARY AIR VANES (IF REQUIRED)
DIRECTION OF FLOW
SUPPORTING FUEL NOZZLES (IF REQUIRED)

Figure 1.

```
LINKING SYSTEM LIB
ENTER BTU/HR (IN MILLIONS)
?3
ENTER BTU/LB
?12260
ENTER TYPE OF SUPPORT FUEL
O -- FOR #2 OIL
G -- FOR GAS
?G
ENTER % CARBON
?70.72
ENTER % HYDROGEN
?7.36
ENTER % OXYGEN
?14.73
ENTER % FIXED CARBON
?43.24
ENTER % ASH
?8
ENTER ASH SPECIFIC GRAVITY
?1.4
ENTER ASH PARTICLE SIZE IN MICRONS
?.2
ENTER ASH FUSION TERMPERATURE FLUID
?2350
ENTER % MOISTURE
?10
ENTER PARTICLE EMISSIVITY
?.95
ENTER MATERIAL SPECIFIC GRAVITY
?1.2
TEST IGNITION TIME MATERIAL AS RECEIVED
?.162
ENTER IGNITION TIME MATERIAL DRY
?.162
ENTER LIFTING VELOCITY of 90% - TILE PARTICLE
?65
ENTER 90% - TILE PARTICLE SCREEN SIZE IN MICRONS
?100
ENTER 50% - TILE PARTICLE SCREEN SIZE IN MICRONS
?30
ENTER 10% - TILE PARTICLE SCREEN SIZE IN MICRONS
?5
ENTER % FOSSIL FUEL
?5
ENTER WALL THICKNESS
?.75
ENTER CONE ANGLE
?107
```

Figure 2. Program Input Data.

```
LBS OF SOLID FUEL/HR                          232.4633
CUBIC FEET OF GAS/HR                          149.5215
CFM AIR SOLIDS VANE                           477.2646
CFM SUPPORT FUEL                              24.1726
TOTAL CFM COMBUSTION AIR                      501.4373
AERODYNAMIC                                   .8271E-04
CYLINDER DIAM. INCHES                         8.6467
CYLINDER WALL THICKNESS INCHES                .7500
MAJOR DIAM. OF BURNER                         18.1491
LENGTH OF IGNITION SECTION INCHES             NONE
LENGTH OF COMBUSTION SECTION, INCHES          7.2972
WIDTH OF SUPPORTING FUEL VANE, INCHES         NOT USED
ANGLE OF INJESTION IN DEGREES                 69.3950
INJECTION VELOCITY FEET/MINUTE                3286.0000
WIDTH OF SOLIDS FUEL VANE, INCHES             2.5624 COMBINED
OPTIMAL NUMBER OF INJECTION PORTS             4
CONE PARTICLE CUT IN MICROS                   1.6099
```

Figure 3. Computer Generated Sizing Data.

```
PARTICLE SIZE CORRELATION

ARITHMETIC MEAN SIZE OF COLLECTED             % OXYGEN
  FLY ASH IN MICRONS

2.5                                           3.5
3.6                                           0.0
2.8                                           1.3
3.2                                           1.0

PREDICTED 2.21 MICRONS
```

Figure 4.

SUB BITUMINOUS COAL
    FLY ASH AS PER CENT OF TOTAL ASH
        4.2

    FLY ASH CARBON
        21.26%

    TOTAL PARTICULATE EMISSIONS IN LB/MBTU
        .40

    SO_2 EMISSION
        392.5 PPM
        .66 LB/MBTU
        THEORETICAL SO_2
        1.64 LB/MBTU
        40% OF AVAILABLE SULFUR EMITTED AS SO_2

    NO_X EMISSION
        252 PPM
        .30 LB/MBTU
        THEORETICAL NO_X (BY FUEL NITROGEN)
        .86 LB/MBTU
        35% OF AVAILABLE FUEL NITROGEN EMITTED AS NO_X

Figure 5. Particulate Emissions.

SESSION IV - POSTCOMBUSTION CLEANUP

SESSION CHAIRMAN: Sidney R. Orem, Industrial Gas Cleaning Institute

The previous sessions have dealt with preparing coal, cleaning it and burning it in a variety of ways. The papers in this session highlight the present state of technology on backend cleanup of products of combustion. Topics include two methods for high efficiency particulate control, flue gas desulfurization and flue gas treatment for NO_x control.

Some of you no doubt heard that the Senate/House Conference Committee reached a compromise report on the Clean Air Act Amendments at 2:15 a.m. yesterday. Action is expected in both houses before adjournment tomorrow for the August recess.

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"ELECTROSTATIC PRECIPITATION
STATE OF THE ART"

by

Dr. R. S. Atkins & D. V. Bubenick

Research-Cottrell

It is extremely appropriate during this symposium on the Clean Combustion of Coal to discuss electrostatic precipitation. Electrostatic precipitation has played a major role in controlling coal-fired boiler emissions and will continue to play a significant role in the future. In fact, if it were not for this technology, environmental pressures would not have permitted the coal-fired boiler market to have grown to its present size (Figure 1).[1] Likewise, many significant improvements in this and other pollution control technologies developed as a result of the "1970 Clean Air Act" which necessitated stricter pollution control requirements and performance standards. The precipitator was first applied to fly ash control problems in 1923 but many significant technological advances are occurring now. With government and economic pressures for a more coal-dependent economy, we will continue to see many more improvements in electrostatic precipitation to meet these needs.

The electrostatic precipitator is the major high efficiency particulate control device for coal-fired boilers. Figure 2 illustrates that as late as the 1960's, the average user required only about 97.5% particulate collection efficiency.[2] With today's pollution control laws, we are designing and supplying systems with an average removal efficiency of 99.5% and in some instances a design requirement of 99.9%.

The demand for higher efficiencies, the use of more strip-mined low sulfur western fuels, the site-specific situations and their resulting economics necessitate the consideration of alternate pollution control devices. Baghouses, scrubbers, electrostatic precipitators and combinations thereof are offered by the company I represent depending upon customer needs, pollution codes and economics. Each situation requires the selection of an appropriate control device strategy. However, today I will only discuss the electrostatic precipitator, where it is and where it is going.

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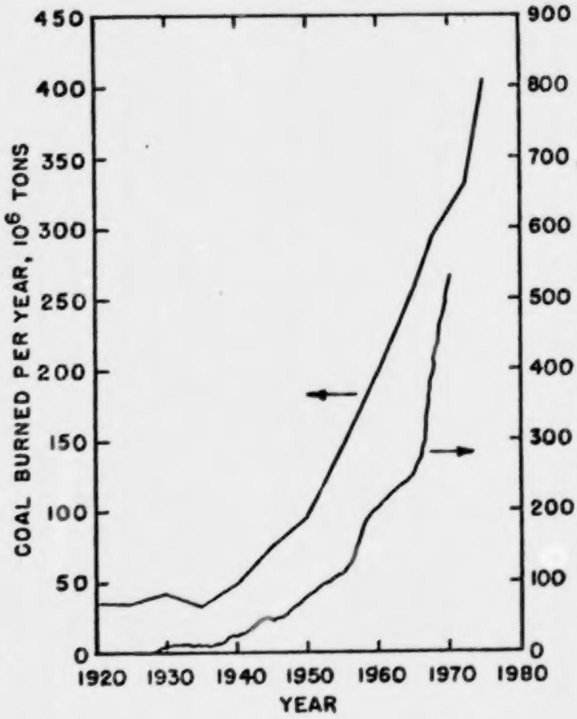


FIGURE 1. COAL CONSUMPTION AND INSTALLED FLY ASH PRECIPITATOR CAPACITY FOR PUBLIC UTILITIES IN THE UNITED STATES, 1920-1975.

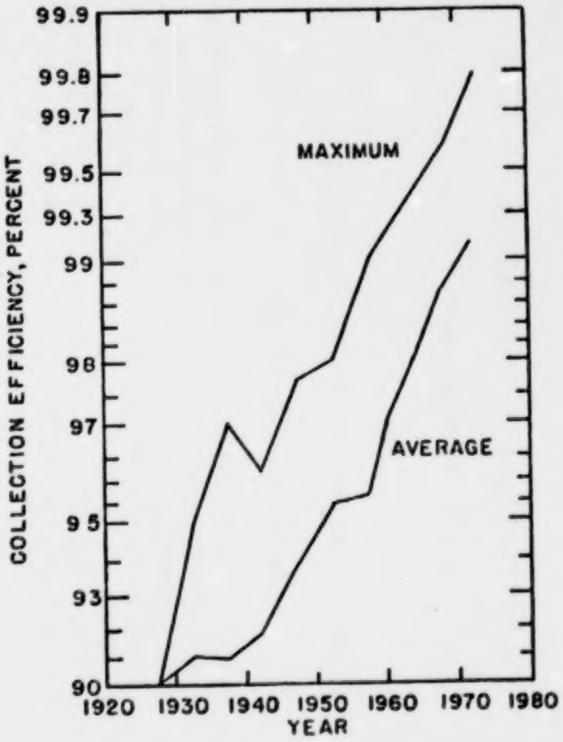


FIGURE 2. TRENDS IN THE AVERAGE AND MAXIMUM COLLECTION EFFICIENCIES OF FLY ASH PRECIPITATORS IN THE UNITED STATES.

What is an Electrostatic Precipitator?

The conventional coal-fired boiler electrostatic precipitator as we know it today is a rectangular configuration with the gas flowing between parallel grounded plates, called collecting electrodes, interdispersed with regularly spaced discharge electrodes. Usually the discharge electrodes are flexible weighted wires, rigid masts or other electrode geometries which are of negative polarity to provide a source of electrons which produce ions for charging the dust particles.

The charged dust is electrically attracted to the collecting plates where it deposits and is removed from the gas stream. Collected particulate is released from the collecting and discharge electrodes during on-stream operation by rapping and vibrating devices. The collected dust falls by gravity into hoppers located beneath the precipitator. The system is designed for continuous operation with multiple ducts and chambers in parallel to handle the volume of gas and different lengths of treatment to achieve desired collection efficiency levels (Figure 3)[3].

The precipitator can be located up or downstream of the boiler air heater and respectively operated at 650 to 850°F (hot precipitator) and 250 to 350°F (cold precipitator). The face velocity through the precipitator typically ranges from 3 to 6 ft/sec. Various discharge and collecting electrode geometries are used depending on the dust properties. Most units use 8 to 12 inch plate spacing with various treatment lengths depending on the degree of high tension sectionalization required. Discharge electrodes are equally spaced on centers between the plates. Full and half wave D.C. current is used to negatively charge the discharge electrodes with respect to the grounded plates. Typical levels of corona power density range from 0.5 to 3.5 watts/ft^2 of collecting surface corresponding to resistivity levels of 10^{13} to 10^{8} ohm-cm.

Today's precipitators have a combined charging and collecting function in the same treatment length. This has resulted in a compromise between charging and collection properties to obtain optimized single-staged performance. Theoretically better performance may be obtained by designing units with independent charging and collecting sections as illustrated in Figure 4 to optimize their individual needs. Two-staged precipitator research was conducted many years ago but progressed no further than the laboratory, possibly because the then moderate performance requirements could not justify the increased costs. However, work in this area is again being con-

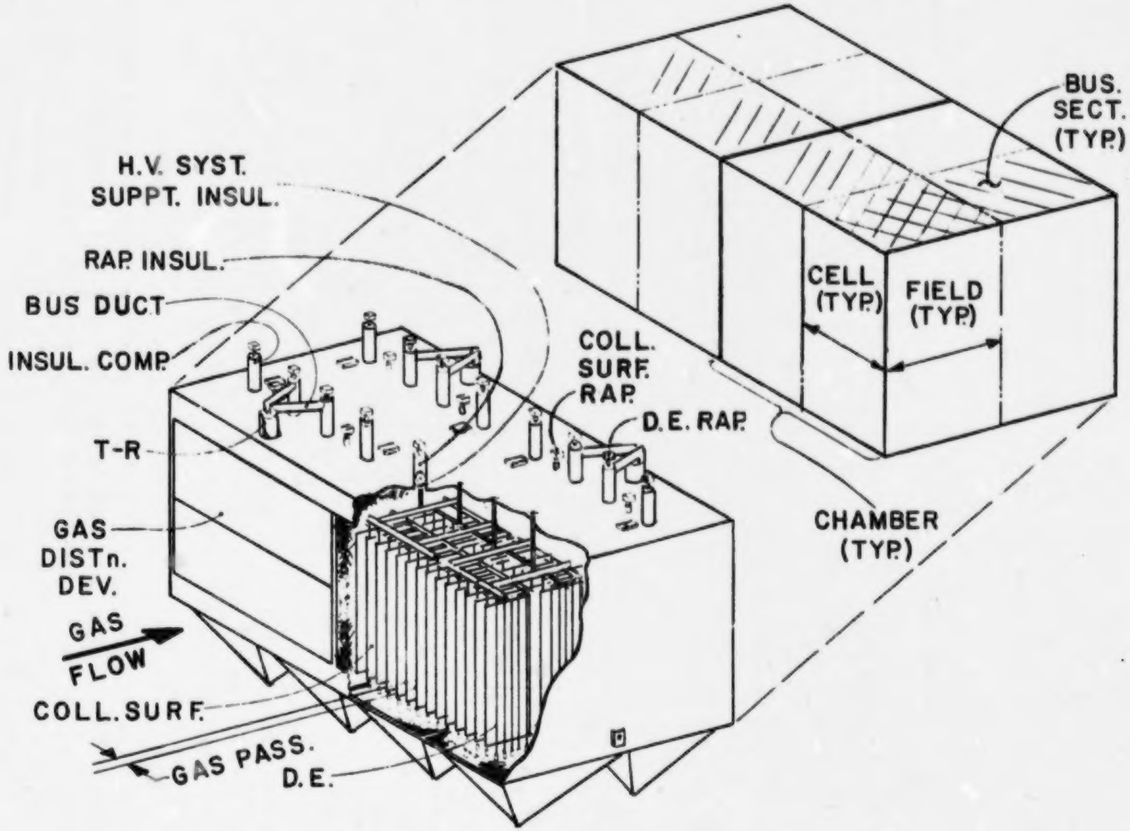
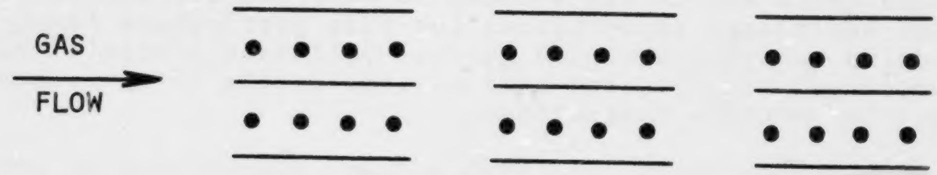
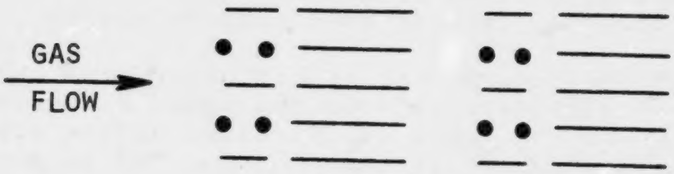

BUS. SECT. (TYP.)
H.V. SYST. SUPPT. INSUL.
RAP. INSUL.
BUS DUCT
INSUL. COMP.
COLL. SURF. RAP.
D.E. RAP.
CELL (TYP.)
FIELD (TYP.)
T-R
CHAMBER (TYP.)
GAS DISTn. DEV.
GAS FLOW
COLL. SURF.
GAS PASS.
D.E.

FIGURE 3. TYPICAL PRECIPITATOR CONFIGURATION.

CONFIGURATION



SINGLE-STAGED PRECIPITATOR



TWO-STAGED PRECIPITATOR

OPTIMUM PERFORMANCE REQUIREMENTS

CHARACTERISTICS	CHARGING SECTION	COLLECTING SECTION
CURRENT	HIGH	LOW
FIELD STRENGTH	NON-UNIFORM	UNIFORM
MAX. FIELD	AT CATHODE	AT ANODE
SPACE CHARGE	LOW	HIGH
DUST	NONE ON ANODE	COLLECTED ON ANODE

FIGURE 4. COMPARISON OF SINGLE-STAGED AND TWO-STAGED PRECIPITATORS.

ducted by EPRI, EPA, research institutes and precipitator manufacturers to meet the demand for more efficient, less costly equipment. By the end of this decade, large-scale two-staged precipitators with enhanced charging and collecting sections will probably be commercially available. These units may be dry systems or combined dry/wet units with additional capabilities for fine particulate removal, reduced reentrainment and gaseous pollutant control. The two-staged precipitator will be less costly and less sensitive to particle composition.

In conjunction with High Voltage Engineering we are applying pulsed techniques to improve corona generation and the resulting collection of fly ash. The results of our studies continue to be extremely promising. It has shown that this new electrostatic method greatly increases particulate collection at reduced precipitator sizing.

Several other projects in our laboratories have been aimed at control of particulates from the newer combustion methods such as low and high Btu gasification units, atmospheric and pressurized fluidized bed boilers, MHD generators and combined-cycled systems. Each of these processes has its own distinct collection problems which are somewhat dissimilar to conventional boiler applications. For example, in fluidized bed combustion it is desirable to collect the particulate at elevated temperatures of 1000 to 1500°F and at pressures of 10 to 20 atmospheres. The flue gas stream contains fly ash, high levels of carbonaeous materials and reacted and unreacted limestone. Each of these materials will have a different effect on the performance of the precipitator.

One of the projects that we are working on under an EPA contract is to develop a precipitator for operation up to 2000°F and 500 psia. Our bench-scale unit has successfully operated generating higher than expected corona current levels. We are now seeking a pilot plant demonstration. Today, research is being geared to provide the needed know-how and technology to serve the future coal conversion market place.

What Affects the Design of an Electrostatic Precipitator?

In the design of an electrostatic precipitator, the range of conditions over which the system will operate must be specified. As indicated in Table 1, information on gas flow rate, temperature, and flue gas analysis as well as chemical composition and electrical characteristics of the dust, particle size distribution, and mass loading should be obtained. In many cases this information is not available, extremely general or very variable. In these instances, assumptions based upon fuel analyses, ash

TABLE 1. DESIGN PARAMETERS AND DESIGN CATEGORIES FOR ELECTROSTATIC PRECIPITATORS.

PERFORMANCE-RELATED PARAMETERS

GAS FLOW
GAS TEMPERATURE
GAS (TREATMENT) VELOCITY
SCA
OVERALL MASS COLLECTION EFFICIENCY
FRACTIONAL MASS COLLECTION EFFICIENCY
INLET GRAIN LOADING
OUTLET GRAIN LOADING
GENERATED PLANT POWER OUTPUT
FUEL BURNING RATE

FIRING METHOD AND COAL CHARACTERISTICS

FIRING METHOD
% ASH
% SULFUR
% MOISTURE (AS RECEIVED)
BTU/LB (WET)
SAMPLE SOURCE
ASTM CLASS
MINE, STATE
MINE, COUNTY
MINE NAME
SEAM NAME

ASH CHEMICAL ANALYSIS

SiO_2
Al_2O_3
Fe_2O_3
TiO_2
CaO
MgO
K_2O
Na_2O
Li_2O
P_2O_5
SO_3
SAMPLE SOURCE
MEAN
DEVIATION
SAMPLE TYPE

content, Btu rating, mine source, seam type, boiler configuration, firing methods and efficiency levels must be made prior to selecting precipitator design parameters. Specifications which are too general, or averages of a wide variety of proposed fuels lead to very conservative equipment sizing. However, when many sets of data consisting of ultimate, proximate and ash chemical analyses are provided for each fuel and ash source, the supplier can more adequately design a unit to meet the customer's reliability and efficiency needs. Site-specific design constraints such as space limitations, equipment location, minimum velocity given the ductwork configuration, etc., must also be considered.

For many applications precipitator design parameters are known from prior experience with the same coal. In some cases, estimated parameters must be developed from prior experience with similar fuels. However, problems in meeting design efficiency levels do develop when the fuel being fired differs significantly from that used for the initial design. If better information is made available in the design stages, good performance can be expected with the operating unit.

Ash Resistivity

The electrical properties of the dust often analyzed and reported as resistivity are extremely important in designing a precipitator. For optimum precipitator performance the ash resistivity should be in the range of 10^7 to 10^{10} ohm-cm. Figure 5 indicates the typical effect of sulfur and flue gas temperature on ash resistivity. As can be observed, the ash resistivity increases with decreasing quantities of sulfur and varies significantly with temperature. Also, factors such as flue gas moisture and alkali, Na_2O and P_2O_5 contents as well as Fe_2O_3 levels in the ash have a major effect on particle conductivity and collection.

With low sulfur fuels, the likelihood of back corona occurring increases. Back corona causes a reduction in the precipitator operating voltage and current levels which in turn decreases its performance. Also, higher resistivity ash requires more intense rapping to remove it from the collecting electrodes and thereby increases the possibility for dust reentrainment, structural plate failure and equipment maintenance. Hot precipitators limit back corona and ash rapping problems by operating at higher temperatures and under more optimum resistivity conditions.

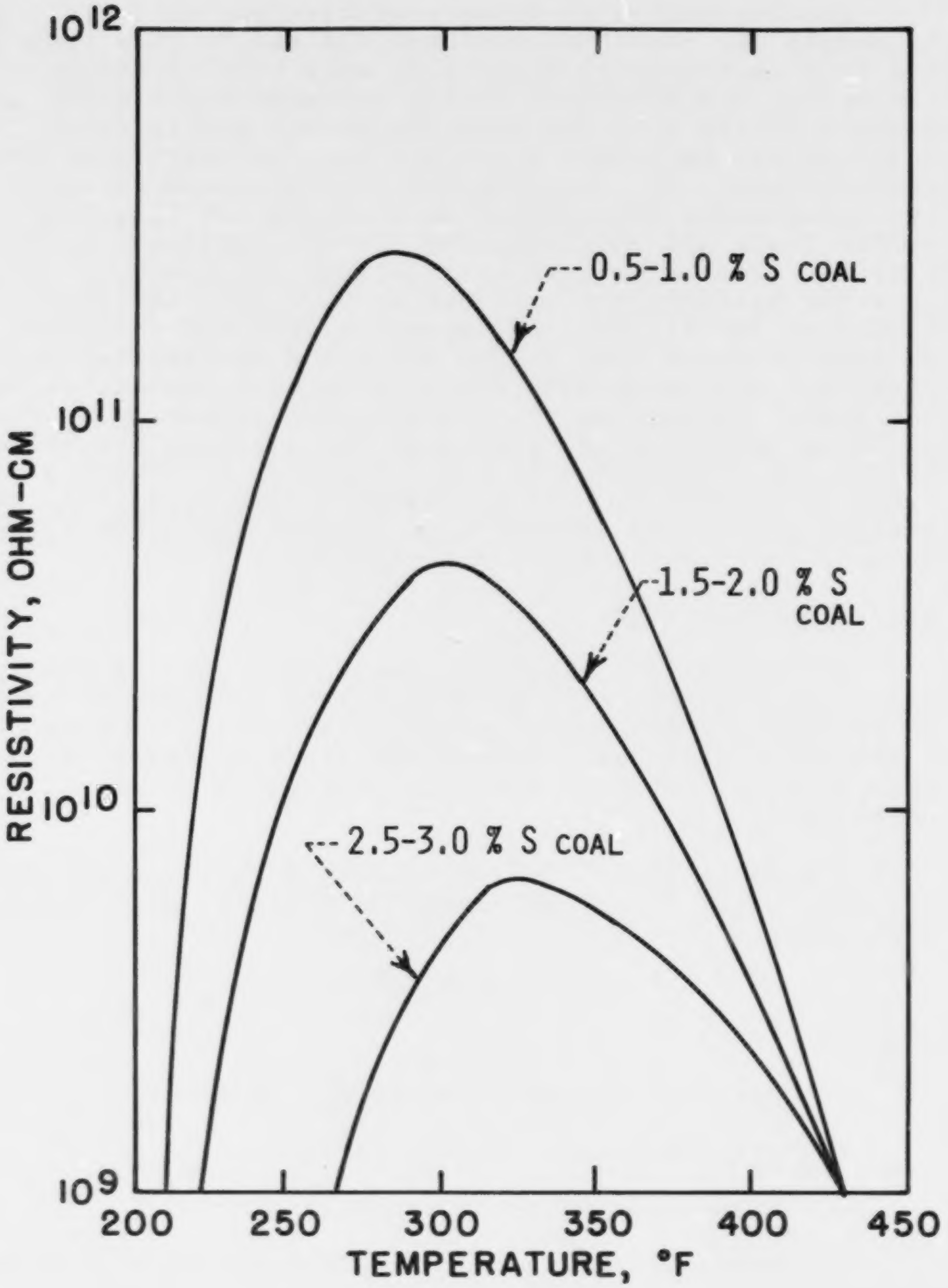


FIGURE 5. EFFECT OF SULFUR CONTENT IN COAL ON FLY ASH RESISTIVITY.

Another method to enhance particulate collection is to modify the resistivity of the fly ash.[4] This technique has been successfully applied in more than 15,000 MW of commercial installations by the addition of chemical additives to the flue gas upstream of the precipitator. SO_3 addition has been used to reduce the resistivity of low sulfur fuels. NH_3 conditioning has been used to increase the resistivity and cohesiveness of fly ash from high sulfur fuels and thus decrease its reentrainment during rapping. Sodium salts also have been successfully applied on a hot precipitator application to reduce the resistivity of the fly ash and improve electrical performance. We have observed that sodium compounds at elevated temperatures can react with other trace constituents of the ash thereby modifying their electrical conduction. Each of these conditioning techniques can increase the reliability and flexibility of a precipitator to handle a wider range of conditions. It is expected that during the next several years, ash conditioning will be specified as part of some new precipitator installations.

Migration Velocity

Whereas resistivity is a rough indicator of precipitator performance, effective migration velocity is used to specify and determine precipitator size. We have developed a good deal of know-how and experience to relate coal, fly ash and flue gas properties to migration velocity.

The conventional Deutsch-Anderson equation was used for many years to relate migration velocity with collection efficiency

$$\eta = 1 - e^{-(A/V)w}$$

where

w = Particle migration velocity, (ft/sec)

V = Gas flow rate, (actual ft^3/sec)

A = Effective collection surface, (ft^2)

η = Overall mass collection efficiency, (fractional).

The migration velocity w is a function of electrical energization and overall mass collection efficiency. The variation in w within a given precipitator is caused by changing particle size distribution as precipitation proceeds in the direction of gas flow. Since the requirement of high collection efficiency corresponds to collection of submicron particles, it is understandable why w decreases with increasing efficiency requirement.

The modified migration velocity, w_k, as presented by Matts and Öhnfeldt[5] can be treated essentially as a constant for any application. We use the modified migration velocity as a more accurate means of predicting precipitator performance.

The following equations used in sizing precipitators relates modified migration velocity with specific collection area (SCA) and efficiency.

$$SCA = \frac{16.67 \ln^2(1-\eta)}{w_k}$$

$$\eta = \left[1 - \frac{\chi\ (H.V.)}{(Ash)\ (A.C.)}\right]100$$

where

SCA = Specific collection area (ft^2/1000 ACFM) = 16.67 (A/V)

η = Overall mass collection efficiency, (percent)

w_k = Modified migration velocity, (ft/sec)

χ = Emission standard, (lb/10^6 Btu)

H.V. = Heating value of the coal,(Btu/lb)

Ash = Ash in the coal, (fraction by weight)

A.C. = Ash carryover, (fraction by weight)

The required overall mass efficiency, therefore, is a function of the coal heating value and ash content as well as the fraction of ash carryover, which is a function of boiler type. The modified migration velocity is a function of electrical energization of the precipitator and of gas properties. It is often conveniently linked with resistivity level, such that for a moderate resistivity of 10^9 ohm-cm the value will be between 1.6 and 1.9 ft/sec whereas for a very resistive dust it may approach 0.5 ft/sec.

Resistivity plays a significant role in the selection of w_k and power density. It is generally predicted from correlation of ash components and knowledge of environmental conditions such as moisture content, gas phase composition, and temperature. Design exponents based on regression analysis are often used in relating coal properties to w_k, SCA, and power density.

Several Selected Case Illustrations

To illustrate some of the points made in the prior discussion, several western low sulfur cold precipitator sizing examples will be discussed. Western low sulfur coals are becoming more important to the U.S. energy picture and have their attendant particulate collection problems. The selected cases represent some of the choices available to the supplier and user in developing an appropriate control strategy.

Table 2 illustrates three types of western low sulfur fuels each exhibiting different precipitator requirements.

Fuel A fly ash has a low silica content with a moderately high level of Na_2O present mainly in the form of sulfates. This condition in lignite coal fly ash yields a favorable conductivity effect; hence the ash has low resistivity and is easily collected with a cold precipitator. Both from technical feasibility and economic viewpoints no other control device option need be considered.

Fuel B is a Colorado subbituminous coal. The fly ash analysis indicates a moderate Na_2O level and a low base (< 20%) and low base/Na_2O ratio (< 10). This suggests that no special precaution must be taken to ensure good operation.[6] However, the high SiO_2 content tends to suppress the conditioning effect of the sodium present. As a result, the resistivity is higher than moderate suggesting that cold, hot, and cold SO_3 conditioned electrostatic precipitators are all technically workable options. The hot Na_2O conditioned option would not be required because of the favorable base/Na_2O ratio which generally suggests that hot precipitators will perform well.

Fly ash analysis of fuel C, a Wyoming subbituminous coal, indicates a base/Na_2O ratio in the marginal range[6] suggesting potential for electrode fouling with hot precipitator operation. Coupled with this is a high P_2O_5 content which is responsible for corona quenching and power-limited hot precipitator operation. The high resistivity shown for fuel C in Table 3 means that a large cold precipitator would be required. Improved precipitator operation and smaller precipitator size for this type of ash can be obtained by increasing the sulfate content using SO_3 conditioning. Sodium salt conditioning can be used to condition the ash to reduce its base/Na_2O ratio and bring it into an improved hot precipitator operating range. In the final analysis, given the technical feasibility of options to be considered, the optimum control device must be determined on the basis of economics and reliability.

TABLE 2. TYPICAL SPECIFICATIONS ON SELECTED WESTERN FUELS.

	Fuel A	Fuel B	Fuel C
Fuel Characteristics			
Rank	Lignite	Subbit.	Subbit.
Location	North Dakota	Colorado	Wyoming
As Fired			
% Moisture	23.9	14.8	28.0
% Ash	6.7	5.1	8.5
% Sulfur	.8	.4	.5
Heating Value (Btu/lb)	8135	10730	8200
Fly Ash Analysis, %			
SiO_2	20.6	45.1	33.0
Al_2O_3	15.6	23.2	15.1
TiO_2	.6	.8	1.0
Fe_2O_3	9.2	5.6	6.1
CaO	31.0	8.8	21.6
MgO	8.8	1.7	4.0
K_2O	3.0	.6	.6
Na_2O	3.4	2.5	1.1
SO_3	6.6	10.7	16.0
P_2O_5	1.2	1.0	1.5
Base	55.4	19.2	33.4
Base/Na_2O	16.3	7.7	30.4

TABLE 3. COLD PRECIPITATOR SPECIFICATIONS FOR SELECTED WESTERN LOW SULFUR COALS.

FUEL COLD COLD PPRT. SPECIFICATIONS	A LIGNITE NO. DAKOTA	B SUBBIT COLORADO	C SUBBIT WYOMING
SCA @ 99.5%	250	440	800
w_k, (ft/sec)	1.87	1.06	0.59
ρ , (ohm-cm)	1×10^9	6×10^{10}	3×10^{12}
η @ .1 lb/10^6 Btu	98.76	97.90	99.04
η @ .05 lb/10^6 Btu	99.39	98.95	99.52

Figures 6 and 7 indicate the relative capital investment ($/KW) and annual cost (mills/KWH) for these various options.[7] From a strictly economic standpoint, it can be observed that SO_3 conditioning in conjunction with cold precipitation, when feasible, is the lowest capital cost approach. However, because of the relative newness of this approach, users are concerned with its long-term reliability. Hot precipitation can be an attractive option and does offer fuel flexibility and reliability. Care must be taken not to universally apply any one solution since we have observed that ash properties can affect even the performance of hot precipitators. Before selecting a particulate control strategy, the various fuels to be combusted in the boiler should be reviewed and their ashes analyzed. A study should be made to determine particulate equipment sizing and its flexibility in handling changes in fuel and in boiler operation. Capital and operating costs should be calculated and only then should a particulate control strategy be selected.

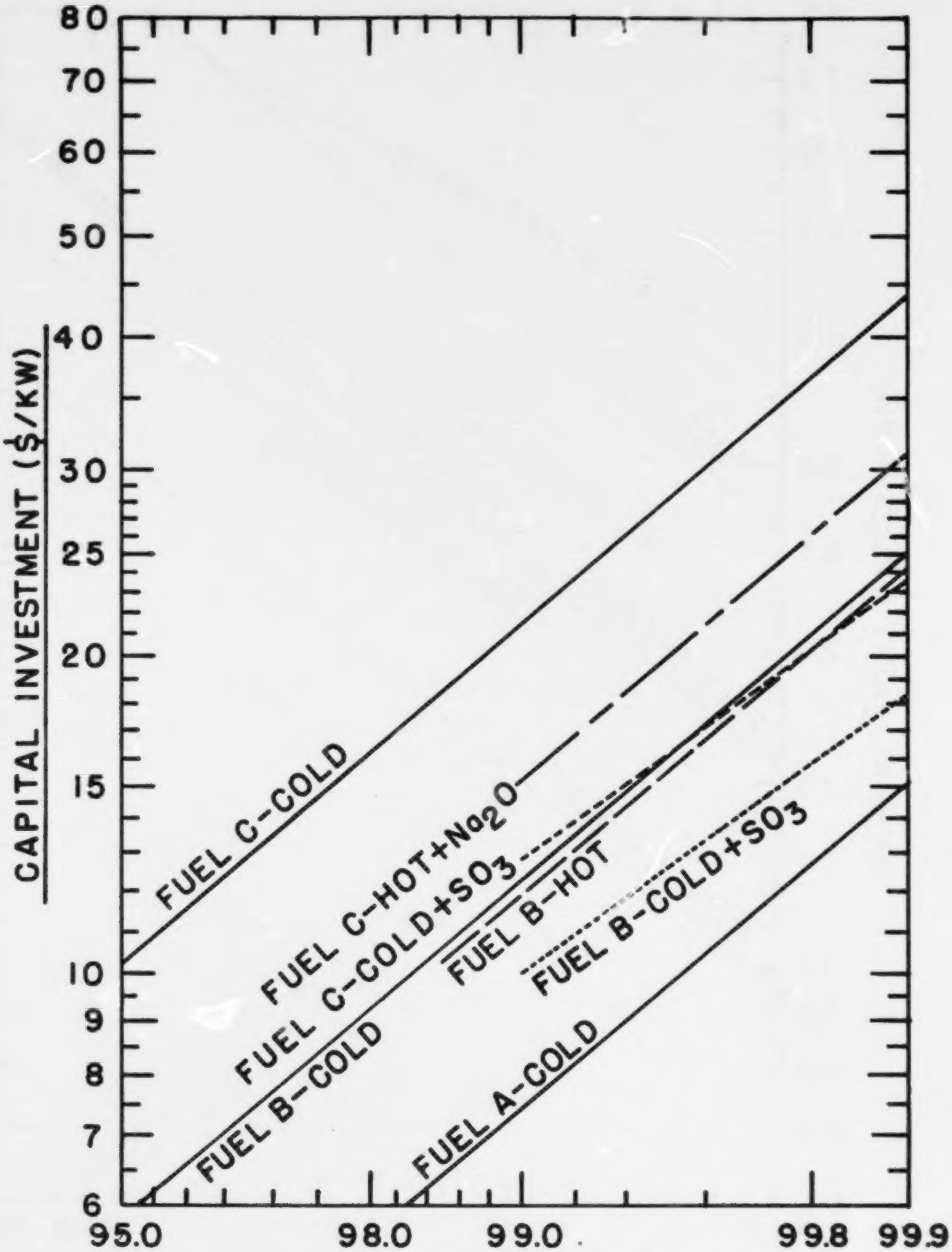


FIGURE 6. ECONOMIC COMPARISON OF CAPITAL INVESTMENTS FOR VARIOUS ELECTROSTATIC PRECIPITATOR OPTIONS FOR A 600 MW POWER PLANT.

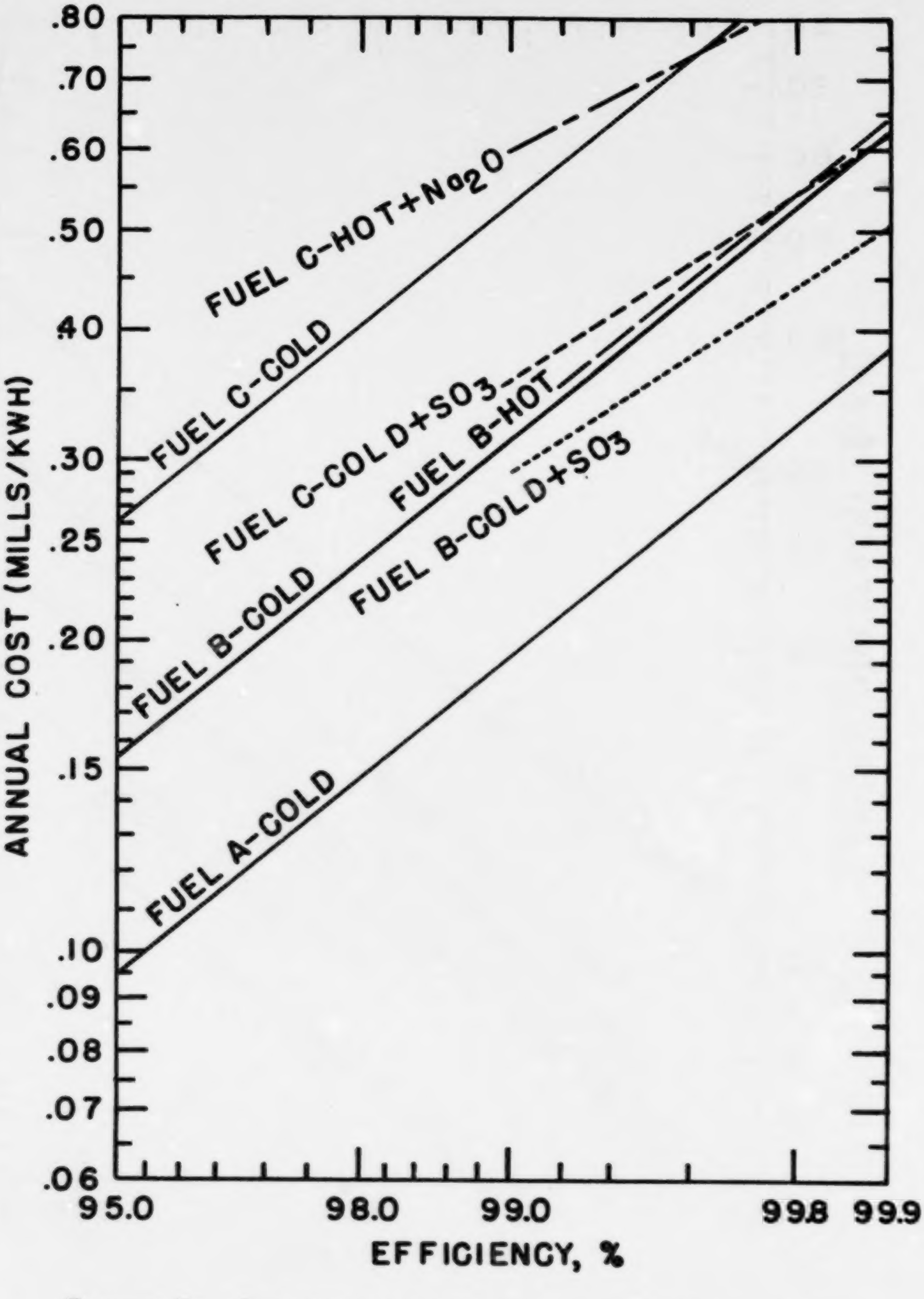


FIGURE 7. ECONOMIC COMPARISON OF ANNUAL COSTS FOR VARIOUS ELECTROSTATIC PRECIPITATOR OPTIONS FOR A 600 MW POWER PLANT.

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STATE OF THE ART -- FABRIC FILTRATION

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INTRODUCTION

If this conference had been held five years ago, there would not have been a paper entitled "State of the Art -- Fabric Filtration." Five years ago, electrostatic precipitators were the only particulate removal device seriously considered for high efficiency removal of fly ash generated by the burning of coal. Certainly, a few pilot fabric filters had been in successful operation by this time but the first full-scale units were still on the drawing board. Today, fabric filters are being installed on both utility and industrial coal-fired boilers. Since fabric filters are probably one of the oldest means of removing solid particulate from the gas stream, what are the reasons for the long delay in their consideration for use on coal-fired boilers and their quick acceptance once the barrier was broken?

The promulgation of the laws pertaining to new source emissions by the EPA in 1970 brought about requirements for emission control that were in most cases substantially more stringent than those which had been in existence up to that time. These requirements for increased efficiency of the pollution control devices substantially increased the size and thereby the cost of an electrostatic precipitator installation. In addition, new sulphur regulations have increased the usage of low-sulphur, Western coal and this has also placed an increased burden on an electrostatic precipitator. Finally, because of earlier difficulties with precipitator performance, a greater degree of conservation was included in precipitator sizing and specifications. The net result of all of these changes was to cause a marked increase in the cost of an electrostatic installation and suddenly the fabric filter was more than competitive in certain areas. Figure No. 1 shows the cost of both the fabric filter and an electrostatic precipitator as a function of plant size and in the case of precipitators, specific collecting area. It will be noted that where a cold electrostatic side electrostatic precipitator has a requirement for an SCA above approximately 500 the fabric filter will normally result in a less expensive installation.

Today, there are several fabric filters in operation, some with operating histories of over four years. Within the next year, many large units (up to 575 megawatts) are scheduled to go into operation. This paper will briefly trace the history of fabric filtration on coal-fired boilers over the past five years and present our thoughts as to the future.

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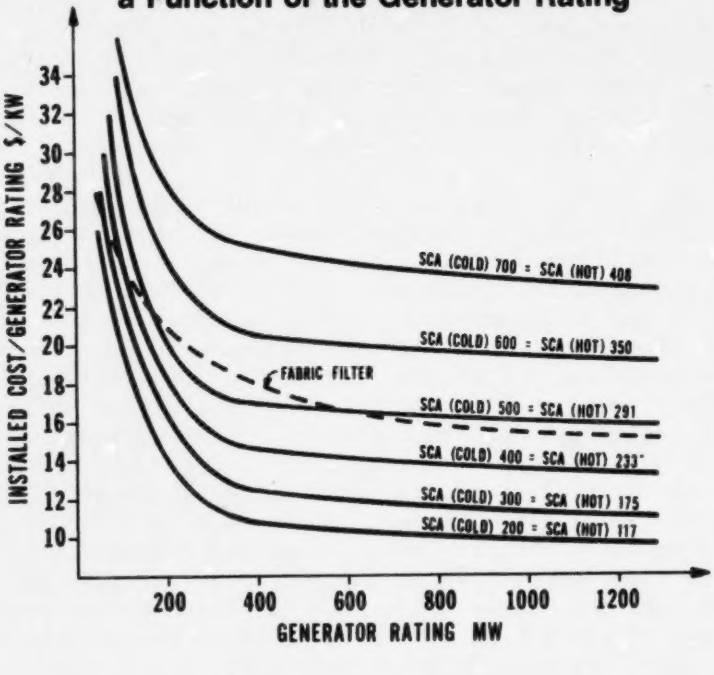
Figure 1

Installed Cost of a Fabric Filter and Electrostatic Precipitator as a Function of the Generator Rating



TYPES OF FABRIC FILTERS

For those somewhat unfamiliar with fabric filtration, it should be pointed out that there are two types of fabric filters that may be considered for use on a coal-fired boiler. These are the so-called high-energy fabric filter and the low-energy fabric filter. In a low-energy fabric filter, as shown in Figure No. 2, filtration is accomplished by building a filter cake using a woven filter fabric as a grid or matrix to support this cake. The cake is intermittently removed from the filter fabric by use of mechanical agitation or by backwashing the cloth.

In a high-energy fabric filter, as shown in Figure No. 3, a felt is utilized which acts as a depth filter as well as supporting a cake on the surface of the felt. In order to remove the collected material from this type of filter fabric, it is necessary to apply a great deal more energy, thus the term high-energy fabric filter. Normally, this energy is applied by utilizing compressed air which will both agitate and backwash the filter fabric and remove the filter cake. Currently, high-energy filters have been applied only to the smaller industrial boilers. The filter fabric utilized has been felted Teflon^{TM} or a heavy woven fiberglass. We would expect to see, however, a greater use of high-energy fabric filters in this service in the future.

To-date, most of the major installations in the utility industry in this country have utilized low-energy filtration. Fiberglass is the normal filter fabric employed in low-energy filters but there is a great deal of discussions currently with regard to the proper finish on the fiberglass fabric. There are also two very different fabric cleaning systems used today on low-energy fabric filters. There is a system called "deflate and shake" and a system utilizing "reverse flow." Both these will be described later. It is interesting to note that while fiberglass has been the normal fabric in this country, synthetics such as acrylics and polyesters have been used with a great deal of success in Australia.

To this day, fabric filtration is still more of an "art" than an engineering science. There are approximately 40 variables that can affect the performance of a fabric filter and most of these cannot be predicted at the time of initial design. We are thus in the position of having to rely heavily on actual field operating experience to make judgments as to the proper application of fabric filters. Just as there is little or no correlation between resistivity and the precipitator sizing factor "W" there is also little correlation between laboratory values of "K" factor or filter drag and actual field performance. It might be well, therefore, for us to review three fabric filter installations on coal-fired boilers which have been in operation for sufficient time to allow us to make judgments as to their performance.

OPERATING EXPERIENCE

In reviewing these installations, we will examine the operating problems encountered with each. However, these problems have been

Figure 2
Low Energy
Filter

Reproduced from
best available copy.

Figure 3

High Energy Filter

minor and it should be noted that none of these units has caused the loss of production on a single kilowatt of electrical power. When compared to the records of other types of control devices being applied to utility boilers, we believe this is an enviable record.

The first full-scale fabric filter installed in the United States on a coal-fired utility boiler is the installation made at Pennsylvania Power & Light's Sunbury Station. There are four units, each handling 222,000 ACFM @ 325°F from two 87.5 megawatt boilers. The first of these units was started in February of 1973. The detail design data for these units is given in Table No. 1.

The performance of the units at Sunbury since their initial start-up has been excellent. The problems encountered have been related primarily to design concepts developed for this job due to peculiarities in space and plant layout, since it was a retrofit. The fabric filter installed at Sunbury operates as a pressure unit, i.e., it is on the discharge side of the I.D. fans, and the gases are forced through the fabric under pressure and then exhausted to the atmosphere. Since reverse gas cleaning is utilized, it is not necessary from a fabric cleaning standpoint to have completely tight gas shutoff valves on each compartment. However, the valves supplied on this installation should also function to allow maintenance workers to enter the compartments for inspection and bag replacement and since they are not gastight on this installation, the only time it is possible to enter the compartments without the use of protective equipment has been during boiler shutdown. Adequate attention to this detail during the initial design phase could have overcome the problem.

Since the Sunbury baghouses operate under pressure, they were also designed such that the reverse air fan was located on the dirty gas side of the unit and the reverse air fans handle fly ash laden gases. Wear problems have been encountered with these fans and maintenance in this area has been high. The fans have not, however, caused a reduction in fabric filter availability.

The next units which we would like to examine were installed at the Nucla Station of the Colorado-Ute Electric Association. In this case, there were three units each ventilating a 13 megawatt stoker-fired boiler. The detail design data for these units is given in Table No. 2. The first of these units was placed into service in December 1973 and the others followed in early 1974. These units were suction-type with I.D. fans located downstream from the fabric filter and none of the problems associated with the Pennsylvania Power & Light units at Sunbury were encountered.

Shortly, after start-up, however, it was noted that there was excessive wear on the bottom of the fabric tubes. The type of tube attachment used in these collectors is shown in Figure No. 4. A study of the problem was initiated and it was determined that the density of the collected material was not 50 lb. per cubic foot as specified by the consulting engineer but rather approximately 25 lb. per cubic foot. This, coupled with the hopper emptying procedures, caused an excessively high level of collected fly ash in the hoppers and thus caused reentrainment and excessive wear on the bottom of the filter

Table No. 1

Pennsylvania Power & Light

Sunbury, Pa.

Boiler	Pulverized coal
Size	400,000 lb./hr. steam 222,000 acfm @ 325°F
Coal	Anthracite and coke
Design	2.07 to 1 air/cloth ratio 2 gr./acf, 2.5-3.5 inch w.g. 99.9% plus

Table No. 2

Colorado-Ute

Boiler	Spreader stoker Traveling grate
Size	132,000 lb./hr. steam 86,200 acfm/300°F
Coal	Ave. 0.7% sulfur (bituminous) 35% ash
Design	3.35 to 1 air/cloth ratio Ave. 1.5 grains 4-inch pressure loss, 99.9% + design

Figure 4

Tube Attachment and Baffles

bags. In order to correct the problem, the hoppers were lowered approximately two feet to provide added capacity and additional baffling was installed. Finally, thimbles for each DUSTUBE which form protecting extensions were installed on the bottom of the tube sheets. This arrangement is also shown in Figure No. 4.

It should be noted that a fabric filter almost identical to those at Colorado-Ute was also installed at this time on a coal-fired boiler in the Nyssa, Oregon, plant of the Amalgamated Sugar Company. This unit was put into service in September of 1973 and had a history very similar to that described for the units at the Colorado-Ute Electric Association. The operating data for the unit at Amalgamated Sugar is given in Table No. 3.

The third unit to be examined is the Penna. Power & Light installation at Holtwood, Pennsylvania. This unit handles 200,000 CFM or approximately 50% of the discharge from this 80 megawatt boiler. The remaining 50% is handled in an existing wet scrubber. The unit became operational in April 1975. The design and operating data is given in Table No. 4. Shortly, after start-up of the PP&L installation at Holtwood, it was noted that there was a gradual increase in the operating pressure drop across the unit. This increase did not seem to be related to any external operating conditions. An investigation into the problem revealed that it was most likely related to the finish used on the fiberglass filter fabric.

All of the early deflate-and-shake units, including the pilot plants which had been operated over the prior ten years, had used fiberglass filter fabric coated with a silicone graphite lubricant. The filter bags in the PP&L installation at Sunbury, however, were fiberglass-coated with Teflon B as a lubricant. The Sunbury bags were equipped with rings and cleaned by reverse air only. It was decided in view of the excellent operating history of Teflon-coated fiberglass at Sunbury to utilize Teflon-coated fiberglass on the Holtwood installation. It wasn't recognized that the finish might not be compatible with the different cleaning method utilized at Holtwood.

Investigation of the increasing pressure drop problem at Holtwood indicated that it was most likely due to the Teflon B finish used on the fiberglass bags. Photomicrographic studies showed that the Teflon appeared to flow and to fill some of the crevices between individual fibers. Figure No. 5 shows this situation. As a contrast, the silicone graphite finish, Figure No. 6, appeared to leave the fibers in a more open condition. It is unknown why the Teflon B finish performed satisfactorily in conjunction with the ringed reverse air cleaning at Sunbury and in a less satisfactory manner in conjunction with the deflate-and-shake cleaning at Holtwood.

To confirm the results of the laboratory investigation, a complete compartment in the Holtwood baghouse was fitted with silicone graphite fiberglass fabric. Operating comparisons were made with respect to volume and pressure drop between the compartment with the silicone graphite finish and the compartments with Teflon B finish. The results indicated that silicone graphite would operate at a substantially lower

Table No. 3

The Amalgamated Sugar Co.

Boiler	Spreader stoker Traveling grate
Size	200,000 lb./hr. steam 91,800 acfm/300°F
Coal	0.5% sulfur (bituminous) 5% ash
Design	3.56 to 1 air/cloth ratio 2.0 grains, 3-inch pressure loss 99.9% design

Table No. 4

Pennsylvania Power & Light

Holtwood, Pa.

Boiler	Pulverized coal
Size	1/2 of 700,000 lb./hr. steam 200,000 acfm 360°F
Coal	1.8% sulfur (anthracite)
Design	2.42 to 1 air/cloth ratio 7.4 to 8 grains, 2.8-inch pressure loss 99.9% + design.

Figure 5
Fibreglass With
Teflon®B Finish (10,000 X)

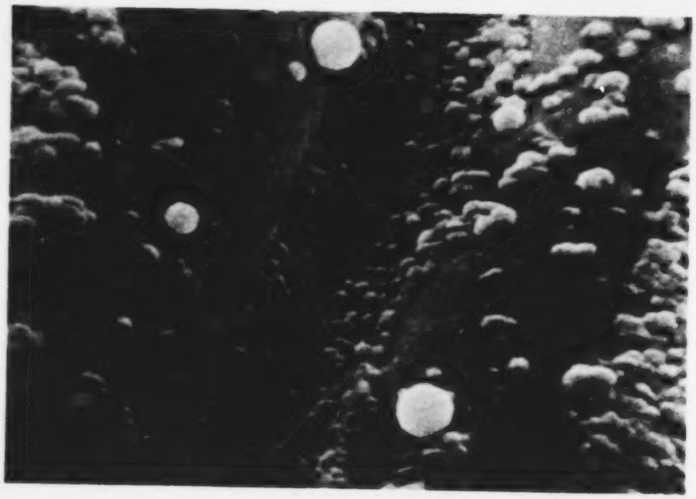
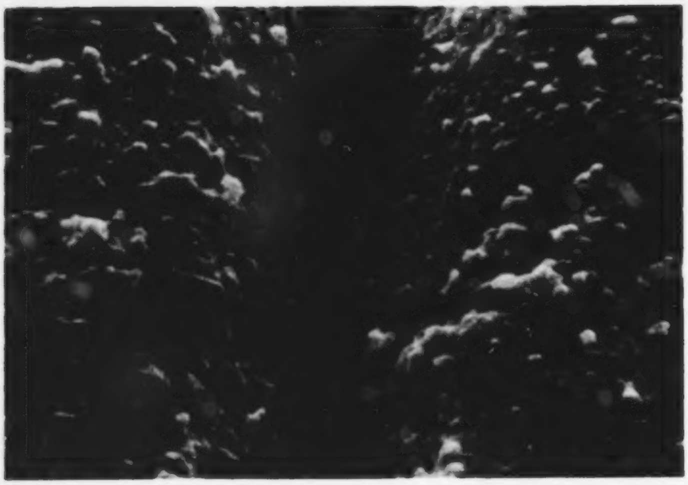


Figure 6
Fibreglass With Silicone Graphite Finish (10,000 X)



pressure drop when handling the same volume of gas. The Holtwood baghouse was then changed so that 11 of the compartments, except for the two control compartments which were left with the original Teflon B finished bags, were converted to silicone graphite finish. This conversion resulted in a substantial lowering of the operating pressure drop of the unit.

CURRENT DESIGN PHILOSOPHY

It may be well to examine current design philosophies on fabric filters to be applied to coal-fired boilers. It is far too early to tell which of these design philosophies will prevail over the long run. Each has advantages and disadvantages and only extended periods of operation on many different types of boilers, fired with differing coals, will give the ultimate answer as to which represents the best approach to the problem.

While there is currently a lack of operating data, we believe that pulse-jet type collectors, i.e., high energy equipped with heavy woven fiberglass filter bags will be an attractive answer for some of the industrial segments of this marketplace. It is possible that this type of collector may extend itself into the large utility installations, but additional work history is needed before this type of unit can be considered on a major boiler installation.

Among the low-energy fabric filters, there are two basic design philosophies. One philosophy indicates the use of higher air-to-cloth ratios and deflate-shake cleaning to maintain bag pressure drop. The other philosophy uses lower air-to-cloth ratios and reverse air cleaning of ringed bags. Generally speaking, the design air-to-cloth ratio with deflate-shake cleaning would be approximately 3 to 1 and the design air-to-cloth ratio for reverse air cleaning will be approximately 2.25 to 1 in order to achieve the same overall system pressure drop.

The reason that shake-deflate cleaning can operate at somewhat higher air-to-cloth ratios is because the bags are cleaned more uniformly. Figure No. 7 shows a ringed bag being cleaned by reverse air. In the filtering mode, it is normal for the finer particles to end up in the top of the bag and the heavier particles to be collected in the lower areas of the bag. When reverse flow is applied, the filter cake is removed from the lower surface of the bag first. This opens up the filter fabric in this area and allows short-circuiting of the cleaning airflow and thus interferes with the uniform cleaning of the filter bag. No such phenomena exists in the mechanical agitation of a filter bag where the mechanical energy is distributed evenly throughout the length of the bag.

The Dorsey equation given in Figure No. 8 is the general formulation for describing the performance of a fabric filter. In our experience, we have found the Dorsey equation to be inaccurate but it probably still represents the best simple mathematical model for performance of a filter. Unfortunately, the value "K" is extremely difficult to define and in most cases can only be calculated after a

Figure 7

Bag Cleaning Methods

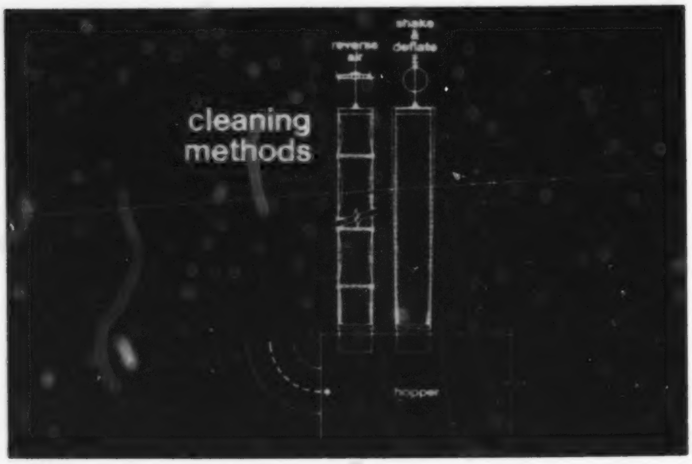

shake
reverse air
deflate
cleaning methods
hopper

FIGURE NO. 8

Dorsey Equation

operating pressure drop

$$\Delta P = KCV^{x}T$$

K	is the specific dust-fabric filter resistance coefficient, usually of order 1 to 10 (in WG/lb/ft^2/ft/min),
C	is the inlet dust concentration (lb/ft^3),
V	is the average filtering velocity (ft/min), and
T	is the operating time between cleaning of a particular compartment (minutes).

unit is in operation. Use of this equation, however, does allow us to compare the relative performance of the two cleaning systems as they are in operation at the Pennsylvania Power & Light Stations at Holtwood and Sunbury. Both boilers burn similar coal. Table No. 5 shows the comparative data between the two installations. We do not believe that this comparison is quantitative but certainly in a qualitative way indicates that the deflate-shake cleaning system provides substantially lower "K" or better filter performance than does the reverse-air cleaning system.

It has been suggested that bag life may be better with reverse-air cleaning. The facts are not available to support this theory at the present time, but if, indeed, it is true, then the relative merits of the two methods will have to be judged on an economic basis. The deflate-shake method will provide for a smaller and generally less expensive initial installation. Should bag life be shorter, this is partially offset by the increased cost of the bags in the reverse-air installation due to the fact that there are a greater number of bags and the bags have sewn-in anticollapse rings. We strongly urge potential users to make a complete economic evaluation between the two proposed cleaning methods. Currently, this would appear to be the most reasonable form of evaluation.

It should be pointed out that in light of the successful operation of fabric filters on smaller boilers, there are currently several units under construction on boilers in sizes ranging from 350 to 575 megawatts. The first of these new large installations will go into operation in the first quarter of 1978 at the Monticello Station of Texas Utilities. In this case, there are two fabric filter systems each handling 80% of the discharge from a 575 megawatt boiler. The remaining 20% of the discharge will be handled by existing electrostatic precipitators. The design data on these units is given in Table No. 6. The utility industry is watching with a great deal of interest these new, large installations and once they are successfully on-stream, we believe that the fabric filter will be considered a viable device for all size boilers.

SO_2 REMOVAL

No presentation regarding the state of the art on fabric filtration with regard to coal-fired boilers will be complete without mentioning that fabric filters are also being considered for the removal of SO_2. There have been successful pilot operations utilizing a fabric filter coated with a naturally occurring sodium bicarbonate called Nahcolite. These filters have been able to remove up to 90% of the SO_2 entering the system and cost analysis indicates that the total system will be more than competitive with the existing wet scrubbing systems.

Finally, fabric filters are also proposed as particulate collectors and chemical contactors following a spray dryer which can remove up to 90% of the SO_2 entering the system. We expect to see increased attention paid to both of these SO_2 removal processes in the near future.

Table No. 5

Operating Comparisons

$K = \Delta P/CV^xT$

Shake/Deflate		Reverse Air
3.75"	ΔP	3.0"
8 gr./cu. ft. ÷ 7000	C	2 gr./cu. ft. ÷ 7000
2.8 fpm	V^x	2.0 fpm
47.0 min.	T	33.0 min.
8.9	K	79.5

Table No. 6

Texas Utilities

Boiler	Pulverized coal
Size	2 boilers 575 MW each 1,840,000 acfm/400°F each
Coal	1.2% sulfur (lignite) 13% ash
Design	2.9 to 1 air/cloth ratio 5.6 to 8.8 grains, 4.5-inch pressure drop 99.9% + design

We believe that the almost-perfect on-stream reliability record of fabric filters on coal-fired boilers combined with their very economical first costs and operating costs will result in an ever-increasing acceptance on both utility and industrial coal-fired boilers. In a way, the use of fabric filters on boilers is in its infancy; however, we have learned much over the past five years and we believe that the time has now come where the fabric filter can take its place alongside the electrostatic precipitator as a device that can economically meet the most stringent emission requirements.

STATUS OF FLUE GAS DESULFURIZATION
THE FEDERAL RESEARCH, DEVELOPMENT AND DEMONSTRATION PROGRAM

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INTRODUCTION

One of the Nation's major energy-related environmental problems concerns the need to control sulfur dioxide (SO_2) emissions from stationary fuel combustion sources. Flue gas desulfurization (FGD) is the term used to denote processes for removal of SO_2 from flue gas, usually by means of a gas scrubbing operation. FGD is the major near-term technological approach to meeting new source performance standards when utilizing high-sulfur coal supplies. In addition, U.S. Environmental Protection Agency (EPA) studies indicate that FGD is competitive in cost with advanced control methods, such as chemical coal cleaning and fluidized bed combustion; therefore, FGD should play an important role in controlling emissions even in the 1990's.

The current Federal energy program calls for a policy of rapid expansion in the use of coal. If this policy is to be successfully implemented, it is essential that FGD technology be fully optimized for application in the utility and industrial sectors.

In the Federal energy/environment research and development program, FGD technology development has been given a high priority. Several FGD studies, pilot plants, prototypes, and demonstration-scale facilities have been funded by EPA. Although prior progress had been achieved in FGD development, the overall pace of development was increased by the initiation, in 1975, of the Federal interagency effort.

The FGD program is being conducted through EPA's Industrial Environmental Research Laboratory in Research Triangle Park, North Carolina (IERL-RTP). The program has aimed at demonstrating reliable and cost-effective FGD processes, including both nonregenerable (throwaway) and regenerable (saleable by-product) systems. EPA's key program in the nonregenerable area is the lime/limestone prototype test program at the Shawnee Steam Plant of the Tennessee Valley Authority (TVA), near Paducah, Kentucky. Other major activities in the area of nonregenerable technology include full-scale demonstrations of double-alkali scrubbing systems, and a comprehensive program in scrubber sludge disposal and utilization.

In the regenerable FGD area, an aggressive program has also been pursued. Full-scale demonstrations of the Cat-Ox (producing 80% sulfuric acid), Wellman-Lord (W-L)/Allied Chemical (producing sulfur), magnesium oxide (producing sulfuric acid), aqueous carbonate (producing sulfur), and the citrate* (producing sulfur) processes have been undertaken.

A number of supporting studies have also been initiated for both nonregenerable and regenerable processes. Included are design and cost evaluations for advanced SO_2 removal technologies, byproduct marketing studies, bench-scale research on key processing steps, investigation of reductants for SO_2 to sulfur, energy optimization studies, and a comparison of utility/industry equipment reliability/availability.

To complement these efforts to develop technology, companion technology transfer efforts are also underway. Through a series of briefings, symposia, capsule reports, summary reports, and a survey of FGD installations, the industry is being aided in its efforts to stay abreast of the rapidly advancing FGD technology. The technology transfer efforts include reporting, to the fullest extent possible, the status of the many full-scale utility and industrial FGD systems designed, constructed and operated under private funding.

The purpose of this paper is to summarize the results and status of the efforts described above as well as the status of FGD technology in the electric utility industry.

NONREGENERABLE SYSTEMS

Lime/Limestone Scrubbing

Lime/limestone processes are the most highly developed FGD processes, having the greatest amount of operational experience. Over 90% of the FGD systems, which have been built, are under construction, or are being planned for service by the early 1980's, are lime/limestone processes.

The Shawnee Program. An important part of the lime/limestone effort involves the operation of a prototype scrubbing test facility at Shawnee Steam Plant. This versatile facility allows comprehensive testing of up to three 10 MW scrubber types under a variety of operating conditions. Bechtel Corporation of San Francisco designed the test facility and directs the test program, and TVA constructed and operates the facility.

The major concerns regarding lime/limestone scrubbing have centered around potential operating difficulties caused by scaling and plugging (especially in the mist eliminator area), the large quantities of waste sludge generated, and the high costs (capital and operating) of scrubbing. It is toward these areas of concern that the Shawnee program has been directed.

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*The citrate process is based on pilot plant work by the U.S. Bureau of Mines

The testing at Shawnee since 1972 has made major contributions toward improvement of lime and limestone scrubbing technology. The most significant results to date include: (1) demonstration, on a 10 Mw scale, that conventional lime/limestone systems can be operated reliably (two separate reliability problems have been identified--scaling and accumulation of soft mud-type solids--and methods to control each have been demonstrated); (2) evidence that mud-type solids deposition is a strong function of alkali utilization and at high utilization (greater than about 85%) these solids are much more easily removed; (3) demonstration of equipment or process variations which individually improved alkali utilization (thereby reducing operating costs), improved SO_2 removal efficiency, and favorably influenced the system chemistry; and (4) development of useful industrial tools, such as the design/economic study computer program and the computerized Shawnee data base.

The EPA Pilot FGD Scrubber Program. The FGD pilot plant operated by IERL-RTP consists of two scrubbers having a flue gas capacity of about 0.1 MW each. They have been in operation since 1972 for the principal purpose of providing in-house experimental support for EPA's larger, prototype scrubber test facility at Shawnee Steam Plant. In addition to supporting Shawnee, the pilot plant also provides IERL-RTP with the capability to independently evaluate new concepts in lime/limestone scrubbing technology.

Results from this pilot unit indicate that forced oxidation limestone scrubbing can be achieved in a two-stage scrubbing system promoting formation of gypsum, a more desirable form of calcium solids, and improving limestone utilization. An extension of this work has recently been undertaken at the Shawnee test facility. Further tests at IERL-RTP have been directed toward achieving the oxidation step in a single-stage scrubber, and information has been developed toward application in larger commercial scrubbing systems. Thus far, it has been demonstrated in the IERL-RTP scrubber that single-stage forced oxidation can be achieved with no loss of SO_2 removal efficiency.

A study of the formation of solid solutions in lime/limestone scrubbers was completed which verified earlier findings made at IERL-RTP that sulfate can be purged with the solids at low oxidation levels while maintaining subsaturated liquor. Larger-scale studies of this "subsaturated" operation mode are being made at Shawnee and Louisville Gas and Electric's (LG&E) Paddy's Run lime scrubber.

Bahco Program. The AB Bahco Ventilation (Sweden) lime scrubbing process has been installed on about 20 small industrial-size oil-fired boilers outside of the United States. Research-Cottrell is the licensee in the United States for this process. The Bahco system appears particularly suited for small industrial applications; it is manufactured in standard sizes of about 5-50 MW equivalent. The system is readily adaptable to a high degree of automation. Although automation results in a somewhat higher capital investment cost initially, labor costs are low because boiler operating personnel can also handle operation of the FGD system.

The Air Force contracted with Research-Cottrell to install a Bahco system for SO_2 and particulate control on up to seven small coal-fired heating boilers (approximately 21 MW equivalent total) at Rickenbacker Air Force Base near Columbus, Ohio. EPA is sponsoring a 2-year test program on this system. Although numerous mechanical problems have been encountered since startup in March 1976, results generally have been promising. Despite the high particulate loading, which at times has been predominately very small sooty particles, design specifications for both the particulate and SO_2 removal efficiency have been exceeded consistently.

LG&E Scrubber Test Program. In November 1974, results from the IERL-RTP pilot-plant testing were reported which showed that lime and limestone SO_2 scrubbers could be operated subsaturated with respect to dissolved $CaSO_4 \cdot 2H_2O$ (gypsum). This mode of operation avoids the problem of gypsum scaling on the scrubber internals. Subsequent investigation indicated that at least two commercial scrubber systems were operating subsaturated with respect to gypsum, one at the Mitsui Aluminum Plant in Omuta, Japan, and the other at Paddy's Run Station of LG&E.

Because of EPA's interest in studying the subsaturated mode of operation on a full-scale system, a program was undertaken at LG&E in the spring of 1976 to evaluate operational and chemical factors (identified by scrubber testing at IERL-RTP and Shawnee) which appear to have an effect on subsaturated operation. The carbide lime phase (baseline tests) of the test program was initiated in October 1976 and was concluded in December 1976. No major scrubber operational problems occurred during these tests. Waste sludge from the system was collected for sludge treatment/disposal tests which are being conducted in conjunction with the scrubber test program.

The commercial lime phase of the test program was initiated in March 1977; shortly after start-up, scaling occurred in the scrubber. The scaling problem was a result of higher oxidation (than with carbide lime) and a lack of gypsum crystals, causing "locally" excessive gypsum saturation levels. The marble bed scrubber used in the tests is also more prone to difficulties from scaling. It has been concluded that the carbide lime contains an oxidation inhibitor in trace quantities. Currently, commercial lime testing has resumed with the addition of small quantities of magnesium oxide to prevent scaling. High SO_2 removals, along with no significant operational problems, have been reported.

Double-Alkali Scrubbing

The double-alkali process provides an alternate wet scrubbing "throwaway" system to the more prevalent lime/limestone slurry scrubbing processes. Such systems employ a clear liquid absorbent rather than the slurry used in lime/limestone processes. As a result, the scrubber in a double-alkali unit is expected to be less prone to fouling and plugging problems.

The double-alkali process is now offered commercially by several companies for control of industrial and utility boilers. Process capabilities include 90% or more SO_2 removal, less than 2% energy consumption exclusive of reheat energy, close to 100% lime/SO_2 stoichiometry, and soda ash consumption in the range of 5% of the lime on a molecular basis. However, these processes may in certain instances be more costly than lime/limestone systems.

Combustion Equipment Associates (CEA)/A.D. Little (ADL) Program. After initial in-house engineering feasibility studies and laboratory experiments in 1971 and 1972, EPA contracted with ADL in May 1973 to conduct a laboratory and pilot-plant study of various double-alkali modes of operation. These efforts included the study of "dilute" and "concentrated" systems, lime and limestone regeneration, sulfuric acid addition for sulfate removal, and solids characterization.

In early 1975 the project was expanded to include a prototype test at the 20 MW facility installed at the Scholz Steam Plant of Gulf Power Company by The Southern Company and constructed by CEA. Testing at the Scholz Steam Plant lasted from February 1975 to July 1976, with the EPA-sponsored portion of the testing beginning in May 1975. As a whole, the prototype system performed very well and indicated that a double-alkali system could be a viable FGD system for coal-burning utilities. SO_2 removal was generally in the range of 90 to 99%.

General Motors (GM) Industrial Boilers Demonstration. GM and EPA have participated in a cooperative program to demonstrate, test, characterize, and evaluate GM's "dilute" mode double-alkali system for control of SO_2 emissions from coal-fired industrial boilers. The program was conducted at GM's industrial boiler complex in Parma, Ohio. The system, consisting of four coal-fired boilers having a steaming capacity of 320,000 lb/hr (equivalent to 32 MW electric generating capacity), was constructed and operated by GM. ADL designed and conducted the test program to evaluate the system with funding from EPA. The test program consisted of three 1-month intensive test periods and longer term nonintensive testing. Each of the intensive tests evaluated a slightly different flow scheme.

LG&E Double-Alkali Demonstration Program. In September 1976, EPA contracted with LG&E for a cost-shared, full-scale coal-fired utility demonstration of the double-alkali process at the 280 MW Cane Run No. 6 boiler. The demonstration project consists of four phases:

(1) design and cost estimation; (2) engineering design, construction, and mechanical testing; (3) startup and performance testing; and (4) 1 year of operation and long-term testing. Construction is expected to be complete by the end of 1978, and testing will begin in early 1979. A contract with Bechtel Corporation has been initiated to design and conduct a test program for the LG&E facility and evaluate the process technically and economically.

FGD Sludge Disposal. One of the major considerations involved in the selection, design, construction and operation of nonregenerable FGD systems is the disposition of large quantities of sludge. Since 1972, efforts have been underway in the EPA FGD research and development program to evaluate and demonstrate sludge disposal techniques. Currently twelve projects are being conducted in this area; these are listed in Table 1. These projects address the two major environmental concerns associated with FGD sludge disposal: (1) the water pollution potential of soluble materials, and (2) the land degradation potential of physically unstable wastes.

Table 1: EPA Projects in FGD Waste Disposal

Project Title	Contractor/Agency
FGD Waste Characterization, Disposal Evaluation, and Transfer of FGD Waste Disposal Technology	The Aerospace Corporation
Lab and Field Evaluation of 1st and 2nd Generation FGD Waste Treatment Processes	U.S. Army Corps of Engineers Waterways Experiment Station
Ash Characterization and Disposal	Tennessee Valley Authority
Studies of Attenuation of FGD Waste Leachate by Soils	U.S. Army Materiel Command Dugway Proving Ground
Establishment of Data Base for FGC Waste Disposal Standards Development	Stearns, Conrad and Schmidt Consulting Engineers, Inc. (SCS Engineers)
Shawnee FGD Waste Disposal Field Evaluation	Tennessee Valley Authority The Aerospace Corporation
Louisville Gas and Electric Evaluation of FGD Waste Disposal Options	Louisville Gas & Electric Company (Subcontractor: Combustion Engineering)
FGD Waste Leachate/Liner Compatibility Studies	U.S. Army Corps of Engineers Waterways Experiment Station
Lime/Limestone Wet Scrubbing Waste Characterization	Tennessee Valley Authority
Dewatering Principles and Equipment Design Studies	Auburn University
Conceptual Design/Cost Study of Alternative Methods for Lime/Limestone Scrubbing Waste Disposal	Tennessee Valley Authority
Evaluation of Alternative FGD Waste Disposal Sites	Arthur D. Little, Inc.

Results in this program area have been substantial. FGD sludge chemical characteristics, to a large degree, have been quantified. Sludge liquors exceed drinking water standards for total dissolved solids (TDS), with high concentrations of calcium, sulfate, and chloride (and in some cases, magnesium and sodium). In addition, excessive concentrations of several trace metals have been noted. The chemical composition of FGD sludge solids consists of calcium sulfite hemihydrate, calcium sulfate dihydrate (gypsum) and/or hemihydrate, and calcium carbonate, plus any fly ash collected in the scrubber. The percentage of each solid constituent is primarily a function of the alkaline additive (e.g., lime, limestone), the percent sulfur in the coal, and the manner in which the scrubber system is operated (e.g., whether forced oxidation is applied, whether fly ash is collected separately). Although the fly ash has been shown to be a major contributor of trace elements to the sludge solids and liquor, separate collection of fly ash does not necessarily mean that concentrations of all these elements in the sludge liquor will be insignificant. In summary, chemical characterization of FGD sludge has shown the need for protection of drinking water supplies from intrusion by sludge leachates.

The physical properties of FGD sludge vary considerably from system to system; chemical composition is related to, but does not adequately define, the sizes and types of the sludge solid crystals. Many FGD sludges tend to liquefy easily, even after substantial dewatering. Several approaches to improving physical stability continue to be studied, including stabilization using underdrainage and compaction, production of gypsum, and chemical treatment ("fixation") for landfill. Chemical treatment of FGD sludge has been shown to result in significant structural improvement, a 50-75% reduction in major solubles (e.g., chloride) in the leachate and an order of magnitude (or more) reduction in permeability. Further testing of these disposal methods, including revegetation (reclamation) of disposal sites, is planned.

The costs of FGD sludge disposal vary considerably, depending on the disposal system design, and site-specific factors such as labor costs or the cost of a pond liner (if one is installed). Preliminary cost estimates for a typical high-sulfur-coal-burning plant are about \$4-\$9 per metric ton (dry basis, including ash) for ponding, and about \$8-\$12.50 per metric ton (same basis) for chemical treatment and landfill. The ponding costs do not include reclamation costs. More detailed economics for these disposal methods have been defined by TVA, and will be reported soon. The next phase of the EPA-sponsored study at TVA will include gypsum disposal.

Costs of FGD sludge disposal represent a major part (up to 20%) of the capital and operating costs of an FGD system. These costs can be drastically reduced by improved absorbent (e.g., limestone) utilization, controlled solids quality, and by improved sludge dewatering equipment. One approach to control solids quality which is currently under study is an attempt to develop a procedure to obtain consistent, easily dewatered sulfite solids. An alternative approach would be to use forced oxidation to produce only gypsum crystals, which are normally much larger than calcium sulfite crystals. A complementary approach is to improve the performance of dewatering equipment. Separation of the clarification and thickening steps can result in improved performance of gravity settlers, with a substantial reduction in the equipment size. With the exception of controlling sulfite solids quality, all of these improvements have been shown to be feasible and are currently making their way into the process supply market. However, further development/refinement of these techniques is continuing; their full commercial use is expected in the next 2-3 years.

Coal-mine disposal of FGD sludge has greatly interested engineers in the flue gas desulfurization industry for many years, because of established means of transportation between the coal mine and the power plant, and the need for material to fill the void left by mining of the coal. In addition, many plants may not have sufficient land area for on-site disposal. Recent technical/economic assessments indicate that active Midwestern surface mines and Eastern/Midwestern room-and-pillar underground mines are the most promising candidates for this disposal approach. One utility plans to begin disposal of FGD sludge and ash in a surface mine this summer. Plans under the EPA program are to conduct a 2-year monitoring/assessment effort at this utility site. Successful demonstration of this disposal approach could make conversion to coal quite feasible even in areas where land for disposal is limited.

Ocean disposal of FGD sludge is also being assessed because many plants in the Northeast may have difficulty switching to coal for lack of disposal sites; however, many of these plants do have access to the ocean. It was also recognized that the major soluble chemical constituents in FGD sludge are found in relatively high concentrations in seawater. Studies of ocean disposal of FGD sludge by Arthur D. Little for EPA have identified several potential environmental problems. It appears that these problems could be alleviated by either chemical treatment to a "brick-like" form (possibly creating an artificial reef) or oxidation to gypsum (followed by a widely dispersed disposal operation). The costs of these approaches are being defined and are expected to be somewhat higher than for chemical treatment/landfill near the plant. Pilot disposal simulation studies are underway to define the environmental effects of both untreated and treated FGD sludge disposal in the ocean.

Currently there are no Federal regulations which specifically address the disposal of FGD sludge. However, the Resource Conservation and Recovery Act (RCRA) of 1976 calls for the eventual Federal regulation of disposal of hazardous solid wastes and the issuance of guidelines (to be used by the states) for disposal of non-hazardous solid wastes. The RCRA specifically identifies solid wastes and sludges, including those generated by air pollution control devices, as being covered by the Act. Although no official designation (hazardous or non-hazardous) has been placed on FGD sludges, it is currently assumed that they will be considered non-hazardous, with disposal guidelines to be issued in the next 2-3 years. An effort has been underway since mid-1975 to prepare a preliminary technical support document which could be potentially useful in setting FGD waste disposal guidelines. A draft of the document is currently under review.

Studies of the characteristics of coal ash and the effects of coal ash disposal have been underway and are continuing. These efforts are not as extensive as those for FGD sludge. However, they are no less significant because of the increasing generation of coal ash, and because many FGD sludges contain significant quantities of fly ash, either collected in the scrubber or added to the FGD sludge prior to disposal (e.g., in a chemical treatment process). A report has been issued which summarizes and evaluates existing data on the characteristics of coal ash from studies made by TVA and others.

FGD Sludge Utilization. This part of the FGD program has only become active in the past 2 years; it currently consists of five projects, listed in Table 2.

Table 2: EPA Projects in FGD Waste Utilization

Project Title	Contractor/Agency
Gypsum By-product Marketing Studies	Tennesssee Valley Authority
Lime/Limestone Scrubbing Waste Conversion Pilot Studies	Pullman-Kellogg
Fertilizer Production Using Lime/Limestone Scrubbing Wastes	Tennessee Valley Authority
Use of FGD Gypsum in Portland Cement Manufacture	Babcock & Wilcox Portland Cement Association C.E. Lovewell
FGD Waste/Fly Ash Beneficiation Studies	TRW, Inc.

Since FGD sludge is a relatively new by-product, utilization in the United States is not yet a commercial reality. However, conversion of FGD sludge to gypsum (or direct production of gypsum) for use in wallboard and portland cement manufacture is practiced extensively in Japan. Although the Japanese experience has primarily been with oil, gypsum-producing FGD experience with coal is increasing in Japan and the United States. However, thus far there have been no full-scale commitments by American utilities to produce FGD gypsum for sale. This situation may change as the utilization of coal for electric power expands and an energy and resource conservation ethic begins to take shape.

Tools for the development of FGD gypsum market strategies have been developed. Studies currently underway at TVA include a thorough economic evaluation of several gypsum-producing FGD processes--e.g., limestone/gypsum, Chiyoda (H_2SO_4/gypsum), and Dowa (aluminum-based double alkali/gypsum)--and a detailed U.S. marketing study of FGD gypsum for wallboard. A report on this study is expected later in 1977; indications are that processes less complex than those used in Japan will be necessary for a profitable situation to occur. Wallboard production using FGD gypsum from a Southeastern utility has been successfully demonstrated. Feasibility demonstration of FGD gypsum used in portland cement in cooperation with trade associations is planned.

Development of FGD sludge utilization in fertilizer is continuing at the pilot level at TVA. Spreading the material over a relatively large land area in this manner would not only alleviate the disposal problem, but would also minimize the potential localized environmental impact of a highly concentrated waste; i.e., the leachate's chemical constituents would be highly diluted by rainfall and interaction with the soil. Further development of the fertilizer production process is needed to establish its viability.

Conversion of FGD sludge to elemental sulfur with recovery of calcium carbonate (using coal as the reductant) for recycle to the scrubber has been studied on a pilot level by Pullman-Kellogg and Ontario Hydro. Further studies are planned under a contract currently being negotiated with Pullman-Kellogg. This effort should be underway later in 1977.

REGENERABLE SYSTEMS

Since its inception in 1970 EPA has assisted in the development of several recovery processes capable of producing sulfuric acid, elemental sulfur, or liquefied SO_2. These processes have been pursued in hopes of conserving a valuable natural resource and reducing overall SO_2 control costs. Most of the EPA efforts have been directed toward full-scale demonstrations of a number of leading processes; however, support has also been given to bench-scale and pilot plant efforts.

Magnesium Oxide Scrubbing Program. The Mag-Ox scrubbing process--developed by Chemical Construction Company (Chemico) and Basic Chemicals, and currently offered commercially by Chemico--is one of the more promising regenerable FGD approaches. The process, which produces sulfuric acid, is widely applicable to both existing and new power plants. It is also amenable to the centralized processing concept; i.e., spent sorbent can be regenerated at a central plant capable of servicing a number of power or industrial plants.

In 1974, EPA and Boston Edison completed a co-funded demonstration program of a 155 MW capacity scrubbing/regeneration system. Results obtained during 2 years of operation indicated: (1) SO_2 removal efficiencies in excess of 90% were obtained consistently, and (2) more than 5,000 tons of saleable sulfuric acid of high quality was recovered from the stack gas and sold commercially. A number of problems were encountered that were primarily equipment, rather than process, related; however, continuous, long-term, reliable operation was not achieved.

In 1973, Potomac Electric Power Company installed a 100 MW Mag-Ox scrubbing system at its coal-fired Dickerson Station. EPA provided the Mag-Ox regeneration system for Potomac Electric's use in processing spent scrubber sorbent. Results indicate SO_2 removal efficiencies greater than 90% are possible and particulate removal of 99.6% was attained. Over 2000 tons of sulfuric acid was produced and marketed. Unfortunately due to a shortage of funds this demonstration did not run long enough to completely answer all questions regarding absorbent recycle, absorbent losses, and process reliability.

Philadelphia Electric will soon begin operating a 120 MW MgO scrubbing facility at the Eddystone Unit 1. After initial startup in September 1975, this unit was shut down when the regeneration-sulfuric acid system at Olin Chemicals, Paulsboro, New Jersey, plant was permanently closed. Regeneration will now take place at Essex Chemical's acid plant in Newark, New Jersey. EPA plans to supply consulting for startup, operation, and test program formulation.

Wellman-Lord/Allied Chemical Demonstration Program. EPA and Northern Indiana Public Service Company (NIPSCO) have jointly funded the design and construction of a flue gas cleaning demonstration plant utilizing the Wellman-Lord SO_2 recovery process and the Allied Chemical SO_2 reduction process to convert recovered SO_2 to elemental sulfur. The operational costs for the system will be paid by NIPSCO, and a comprehensive test and evaluation program will be funded by EPA. The demonstration system has been retrofitted to the 115 MW, coal-fired Unit 11 at the D.H. Mitchell Station in Gary, Indiana. Construction of the facility was completed in August 1976.

Startup activities and acceptance testing were delayed by boiler problems which developed when Unit 11 was shut down for annual maintenance. The boiler and the FGD plant were restarted in June, and integrated operation and acceptance testing will follow shortly thereafter. Long-term duration testing will begin after acceptance.

Bureau of Mines (BOM) Citrate Demonstration Program. EPA and BOM have entered into a cooperative agreement to pool funds and technical talents to demonstrate the citrate process developed by BOM. A concurrent development program, carried out by an industrial consortium headed by Pfizer Chemical Company, also led to a pilot operation of the process. Based on the results of these two pilot programs, EPA and BOM have initiated the demonstration of this technology on a 53 MW coal-fired boiler at St. Joe Minerals Corporation in Monaca, Pennsylvania. Construction of the facility is expected to be completed by mid-1978. After acceptance, a 1-year test and evaluation program will be initiated.

Aqueous Carbonate Demonstration Program. EPA and Empire State Electric Energy Research Corporation (ESEERCO), a research organization sponsored by New York's eight major power suppliers, have recently contracted to fund jointly the design and construction of a demonstration of Atomics International's sulfur-producing aqueous carbonate process. The demonstration system is being retrofitted to

Niagara Mohawk Power Company's 100 MW coal-fired Huntley Station in Tonawanda, New York. Construction of the facility is expected to be completed by mid-1979. After acceptance testing, a 1-year test and evaluation program is planned.

Catalytic Oxidation (Cat-Ox) Demonstration Program. The Cat-Ox process is Monsanto Enviro-Chem Systems' adaptation of the contact sulfuric acid process. EPA and Illinois Power Company attempted to demonstrate the process on a 103 MW coal-fired boiler at Illinois Power's Wood River Station between 1970 and 1976.

Detailed design, construction, shakedown testing, and performance guarantee testing were completed in July 1973. The unit met all guarantees and was subsequently accepted. Because of the shortage of natural gas, the burners were modified to allow either oil- or gas-firing. However, design and startup problems precluded successful operation and initiation of the comprehensive 1-year test program.

In view of the problems and long delays encountered, a thorough technical and economic study was made of the costs and benefits of continuing the Cat-Ox demonstration at the Wood River Station. Results of this study led to the decision to end the project in December 1976.

Ammonia Scrubbing with Bisulfate Regeneration Pilot-Plant Program. In 1970, EPA and TVA jointly undertook the development of a completely cyclic ammonia scrubbing/ammonium bisulfate regeneration process which has as its major product a concentrated stream of SO_2 which can then be used to produce sulfuric acid or elemental sulfur. This process was evaluated at a 3,000 ft^3/min (5,000 m^3/hr) pilot unit located at Colbert Steam Plant. While initial developmental efforts at the pilot unit were concentrated on the absorber, later work included investigation of all subunits of the system except the electrical decomposer. It became apparent that the process had two major problems: (1) the formation of a persistent fume which could not be consistently controlled or eliminated by reasonable control efforts, and (2) unfavorable economic projections due primarily to energy consumption by the decomposer. As a result of these problems, the development project was terminated during the summer of 1976.

FGD SUPPORT STUDIES

Key supporting studies in several problem areas of FGD technology have been sponsored by EPA to further the advancement and application of commercial systems. In many cases, the studies undertaken are broad general assessments which are directed toward a wide variety of potential users. Examples of results from these studies are described below.

Comparative Economics of SO_2 Control Processes

The purpose of this continuing EPA/TVA project is to study the most promising SO_2 removal processes advancing toward commercialization.

It includes selection of those processes which have the greatest degree of development and which are potentially attractive both technically and economically. These evaluations include preparation of flowsheets, material balances, and layouts; definition of process equipment; preparation of capital investments and operating costs; and analysis of design and economic variables for cost sensitivity analysis. Currently, this is being done for the citrate and double-alkali processes using the limestone system for comparison; results should be available by the fall of 1977.

By-product Marketing Studies

TVA is conducting a program for EPA (1) to determine the quantities of FGD by-product acid sulfur and gypsum that would be produced at power plant sources, and (2) to analyze the markets for these by-products. The computer model which has been developed considers compliance of actual utility plants with SO_2 emission standards and potential by-product market demand for each plant (based on current markets and freight rates). Reports on the marketing of sulfur, sulfuric acid, and gypsum (for wallboard) are expected in the fall of 1977.

Reductant Gases

Conversion of SO_x to elemental sulfur requires the use of a reductant; in the past major emphasis was placed on the use of natural gas. Since this is now an impractical approach, other sources of reductant gas must be sought, such as coal gasification. A study conducted for EPA by Battelle-Columbus concludes that a gasifier-based reduction system would significantly increase the complexity of the overall FGD system. However, the gasifier could be used to supply part of the energy for the FGD process, including stack gas reheating.

Magnesium Oxide Scrubbing Support Studies

Two studies in support of magnesium oxide scrubbing have been conducted for EPA by Radian Corporation. In the first study, Radian evaluated the feasibility of producing elemental sulfur directly from magnesium sulfite. This would expand the applicability of current magnesium oxide processes which only produce sulfuric acid. The second study is concerned with the mechanism of formation of trihydrate and hexahydrate forms of magnesium sulfite ($MgSO_3 \cdot 3H_2O$, $MgSO_3 \cdot 6H_2O$). The hexahydrate crystals separate and handle easily; the trihydrate crystals require less drying energy but are more difficult to separate and handle. This study has attempted to generate information on formation mechanisms and operating conditions that can be used to control the type of crystal formed.

Comparison of Availability and Reliability of Equipment Utilized in the Electric Utility Industry

For the past several years one of the major objections of the utility industry to installing FGD systems has been that reliability/availability of FGD systems is much lower than for other major utility equipment items, such as boilers, turbines, generators, electrostatic precipitators, and gas turbines. It is desirable that good information and data on this problem be gathered so that a valid comparison of performance can be made.

To meet this need and to provide information as input for a current National Academy of Sciences study of SO_x control technology, a study by EPA was initiated (with Radian Corporation) as a jointly sponsored project of EPA and the Council on Environmental Quality. The study concluded that a statistically meaningful comparison of reliability/availability of these components cannot now be made, primarily because of the small number and short service time of FGD system data (a meaningful comparison can probably be made in 1979). However, the study also concluded that the mechanical reliability of some types of conventional equipment now being used by the electric utility industry is not much different from that of similar items used in FGD systems.

TECHNOLOGY TRANSFER

For several years, EPA has disseminated FGD technology data and information through the traditional outlets of FGD symposia, industry briefings, capsule reports, and project summary reports. Six symposia have now been held, the last one in March 1976. The next symposium is scheduled for November 8-11, 1977, in Hollywood, Florida. Progress on lime/limestone technology has been reported through industry briefings, the last one in October 1976. Thus far, three capsule reports have been issued on the EPA/TVA/Bechtel Shawnee program. Numerous project reports have also been issued.

In order to improve the effectiveness of the FGD technology transfer effort, the survey of utility FGD installations and, more recently, the Engineering Applications/Information Transfer (EA/IT) program were initiated. These are described below.

Survey of Utility FGD Installations

To meet the continuing demand for technical and economic data on operational, under construction, and planned future utility FGD units, EPA has employed PEDCo-Environmental to monitor this field of technology and prepare periodic reports for use by utilities, system vendors and designers, and regulatory authorities. In addition to detailed technical reports, PEDCo is providing bimonthly status reports indicating the number of each type of SO_2 control system in operation, under construction, or planned in the United States, and the megawatt capacity controlled or to be controlled. The bimonthly status report gives technical and economic information on all known U.S. utility FGD systems categorized in 15 tables and 4 appendices to promote ease of use. Some of the information from the latest PEDCo report April-May 1977) is summarized in the final section of this paper.

Engineering Applications/Information Transfer (EA/IT)

The EA/IT program is a comprehensive effort designed to augment traditional EPA technology transfer efforts so that dissemination of information will be more efficient and effective. The program includes several new and innovative reporting activities, including:

- A series of quarterly reports on FGD research, development and demonstration efforts sponsored by EPA.
- A series of Cost/Reliability Handbooks to assist potential users in choosing the specific SO_x control strategy, FGD system, and FGD system design which best fit their needs.
- Lime and Limestone Scrubbing Data Books (cooperative EPA/Electric Power Research Institute efforts).
- Non-utility (industrial) combustion source survey report assessing applicability of various SO_x control strategies.

FULL-SCALE UTILITY FGD APPLICATIONS

Overview

According to the latest PEDCo survey, 119 utility boilers representing over 50,000 MW of electric generating capacity will be controlled by FGD by the mid-1980's. The current status of these systems is given in Table 3.

Table 3: Status of Utility FGD Systems

Status		No. of Units	MW
Operational		27	7319
Under Construction		29	12648
	Subtotal	56	19,967
Planning			
Contract Awarded		20	9797
Letter of Intent		5	1892
Requesting/Evaluating Bids		5	3565
Considering only FGD Systems		33	14856
	Total	119	50,077

Of the units which are operational or under construction, 91% of the generating capacity or roughly 18,000 MW will be controlled by lime/limestone scrubbing systems. Of the units for which contracts have been awarded, 88% of the generating capacity or roughly 8000 MW will also be controlled by lime/limestone systems. However, of those units in the remaining stages of planning shown above (e.g., letter of intent) for which a process type has been selected, the trend appears to be away from lime/limestone, with only 55% of the generating capacity being planned for control by these systems. However, of the 20,467 MW in these remaining stages, over 13,500 MW, or 66%, represent units for which the specific FGD system has not yet been selected. Therefore, it is perhaps too soon to tell if there will be a substantial move toward the regenerable FGD processes. Nevertheless, as operating experience with regenerable systems increases, particularly with the Wellman-Lord and magnesium oxide systems, they will no doubt occupy a significant portion of the FGD market in the 1980's.

Table 4 summarizes the FGD systems which were operational as of May 1977.

CONCLUSIONS

The experience level of FGD technology is rapidly developing. The development of lime/limestone scrubbing is far ahead of other FGD systems primarily because of information gathered from operational systems and through development sponsored by EPA. If future power plant scrubber systems are designed to take advantage of data already available, improvement in overall reliability, cost, and effectiveness should transpire. Additional work is needed in this area of technology, however, to improve performance, reduce costs, and increase reliability.

Double-alkali technology is rapidly developing as a viable means of SO_2 control. The potential advantages of such systems to improve SO_2 removal, sludge characteristics, and operating reliability first need to be confirmed through the full-scale demonstrations, then applied as an alternate to lime/limestone technology.

The area in which the most work remains to be done is in regenerable process technology. The presently planned demonstrations need to be completed as soon as possible. In addition, further work is needed to confirm the long-term effectiveness and economics of magnesium oxide scrubbing.

Table 4: Summary of Operational Utility FGD Systems*

	Company	Unit Name	Unit Capacity, Mw	FGD Process Type	Coal Percent Sulfur	Start-Up Date	Waste Disposal Method
1.	Arizona Public Service	Cholla No. 1	115	Limestone Scrubbing	0.44-1.0	10/73	(Evaporation) Ponding
2.	Columbus and Southern Ohio Electric	Conesville No. 5	400	Lime Scrubbing	4.5 -4.9	2/77	Chemical Treatment/ Landfill
3.	Commonwealth Edison	Will County No. 1	167	Limestone Scrubbing	4.0	2/72	Chemical Treatment/ Landfill
4.	Duquesne Light	Elrama Power Station	510	Lime Scrubbing	1.0 -2.8	10/75	Chemical Treatment/ Landfill
5.	Duquesne Light	Phillips Power Station	410	Lime Scrubbing	1.0 -2.8	7/73	Chemical Treatment/ Landfill
6.	Gulf Power Co.	Scholz Nos. 1B & 2B	23	Chiyoda 101	5.0 (max)	3/75	(Lined) Ponding (Gypsum)
7.	Kansas City Power & Light	Hawthorn No. 3	140	Lime Scrubbing	0.5 -3.5	11/72	Ponding
8.	Kansas City Power & Light	Hawthorn No. 4	100	Lime Scrubbing	0.5 -3.5	8/72	Ponding
9.	Kansas City Power & Light	LaCygne No. 1	820	Limestone Scrubbing	5.0	2/73	Ponding
10.	Kansas Power & Light	Lawrence No. 4	125	Limestone Scrubbing	0.5	12/68	Ponding
11.	Kentucky Utilities	Green River Nos. 1 & 2	64	Lime Scrubbing	3.8	9/75	Stabilization/Ponding
12.	Louisville Gas & Electric	Cane Run No. 4	178	Lime Scrubbing**	3.5 -4.0	8/76	Ponding
13.	Louisville Gas & Electric	Paddy's Run No. 6	65	Lime Scrubbing**	3.5 -4.0	4/73	Stabilization/Landfill
14.	Montana Power Co.	Colstrip No. 1	360	Lime/Alkaline Ash Scrubbing	0.8	10/75	Ponding
15.	Montana Power Co.	Colstrip No. 2	360	Lime/Alkaline Ash Scrubbing	0.8	7/76	Ponding
16.	Nevada Power	Reid Gardner No. 1	125	Sodium Carbonate Scrubbing	0.5 -1.0	4/74	(Evaporation) Ponding
17.	Nevada Power	Reid Gardner No. 2	125	Sodium Carbonate Scrubbing	0.5 -1.0	4/74	(Evaporation) Ponding
18.	Nevada Power	Reid Gardner No. 3	125	Sodium Carbonate Scrubbing	0.5 -1.0	7/76	(Evaporation) Ponding
19.	Northern States Power Co.	Sherburne County No. 1	710	Limestone Scrubbing	0.8	3/76	(Lined) Ponding
20.	Pennsylvania Power Co.	Bruce Mansfield No. 1	835	Lime Scrubbing	4.7	4/76	Chemical Treatment/ Ponding
21.	Philadelphia Electric Co.	Eddystone No. 1A	120	Magnesium Oxide Scrubbing	2.5	9/75	Not Applicable-- By-product Acid Produced
22.	Tennessee Valley Authority	Shawnee No. 10A	10	Lime/Limestone Scrubbing	2.9	4/72	Ponding
23.	Tennessee Valley Authority	Shawnee No. 10B	10	Lime/Limestone Scrubbing	2.9	4/72	Ponding
24.	Northern Indiana Public Service	D. H. Mitchell No. 11	115	Wellman-Lord	3.5	6/77	Not Applicable - By-product sulfur produced
25.	Northern States Power	Sherburne County No. 2	680	Limestone	0.8	4/77	(Lined) Ponding
26.	Springfield City Utilities	Southwest No. 1	200	Limestone	3.5	4/77	Stabilization/Ponding
27.	Tennessee Valley Authority	Widows Creek No. 8	550	Limestone	3.7	4/77	Ponding

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*Source: PEDCo Summary Report, April-May 1977, Contract 68-02-1321, Task No. 28

**Carbide Lime

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STATUS OF FLUE GAS TREATMENT TECHNOLOGY FOR CONTROL OF NO_X AND SIMULTANEOUS CONTROL OF SO_X AND NO_X

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ABSTRACT

The status of flue gas treatment technology for control of NO_x and simultaneous control of NO_x and SO_x applicable to stationary combustion sources is presented. Dry processes and wet processes are described and applications discussed with respect to performance, operating experience, and economics.

As a result of a very stringent NO_x ambient standard in Japan, the Japanese NO_x flue gas treatment technology appears to be the most advanced in the world. For this reason, Japanese technology is emphasized in the paper. EPA's past, current, and planned flue gas treatment program is also discussed.

INTRODUCTION

Nitrogen oxides (NO_x) in the atmosphere have been determined to have adverse effects on human health and welfare. To aid in preventing these adverse effects, the Industrial Environmental Research Laboratory at Research Triangle Park, N. C. (IERL-RTP) is leading the U.S. Environmental Protection Agency's (EPA) efforts to develop and demonstrate NO_x control technologies for stationary combustion sources. There are two main technologies being developed: combustion modification and flue gas treatment.

> Combustion modification (CM) technology attempts to minimize the formation of NO_x during the combustion process. CM techniques include staged combustion, low excess air operation, flue gas recirculation, water injection, and burner redesign. CM technology should be able to reduce NO_x emissions from stationary combustion sources by 50% or more in a relatively cost effective manner. CM technology will not be discussed in this paper; however, additional information is available from other sources.[1]

Flue gas treatment (FGT) technology attempts to remove NO_x from the gaseous products of combustion. FGT techniques include dry selective catalytic reduction processes and wet scrubbing processes. FGT technology should be able to reduce NO_x emissions by 90% and has the potential for 90% control of both NO_x and SO_x emissions.

NO_x FGT research and development programs have received a relatively low level of funding by EPA since it has not been determined conclusively that high NO_x removal efficiencies will be required to achieve and maintain the current National Ambient Air Quality Standards (NAAQS). However, there are significant uncertainties which may affect the required level of NO_x control. Due to these uncertainties, EPA is proceeding with small scale NO_x FGT experimental projects in parallel with control strategy and technology assessment studies. One phase of the assessment is an evaluation of Japanese FGT technology which has progressed to the point of being commercially applied to gas- and oil-fired sources. In addition, the Japanese are developing processes for application to flue gas from coal-fired sources. EPA is investigating the Japanese and other worldwide technologies for potential application to the U.S. coal-fired situation to save both development time and money. Through these actions, the basic foundation will be established if the technology is required in the United States and acceleration of the development program becomes necessary.

FLUE GAS TREATMENT PROCESSES

There are two main categories of flue gas treatment (FGT) processes for the control of NO_x and the simultaneous control of NO_x and SO_x emissions from stationary combustion sources: dry processes and wet processes. A description of the most promising processes in each category and their developmental status in Japan is discussed below.

DRY PROCESSES

The following dry process types are being developed:

Selective catalytic reduction
Selective noncatalytic reduction
Adsorption
Nonselective catalytic reduction
Catalytic decomposition
Electron beam radiation

Of these, only selective catalytic reduction (SCR) has achieved notable success in treating combustion flue gas for removal of NO_x and has progressed to the point of being commercially applied. The other process types are much less attractive at this time. Selective noncatalytic reduction processes do not achieve high NO_x removal efficiences and adsorption processes are not applicable to combustion sources. Nonselective catalytic reduction, catalytic decomposition, and electron beam radiation processes are at a very low level of development. These process types will not be discussed in this paper, but additional information is available from other sources.[2,3,4,5]

Dry NOx Processes

Selective catalytic reduction processes are based on the preference of ammonia (NH_3) for NO_x over other flue gas constituents. Since the oxygen enhances the reduction, the reactions can best be expressed as:

$$4NH_3 + 4NO + O_2 \xrightarrow{\text{catalyst}} 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \xrightarrow{\text{catalyst}} 3N_2 + 6H_2O \qquad (2)$$

Reaction (1) predominates since approximately 90-95% of the NO_x in combustion flue gas is in the form of NO. Since 1 mole of NH_3 is required per mole of NO, most processes operate with an NH_3/NO mole ratio of 0.9 to 1.1. The reaction temperature is usually in the range of 300 to 450°C, but space velocities vary considerably depending on the process. Under these operating conditions, NO_x removal efficiencies of 90% or greater are typical.[4]

The catalysts used in SCR processes vary with process developer. However, there are some general traits known about the catalysts. The catalyst carrier or substrate is usually alumina, silica, or titanium dioxide. Alumina is satisfactory for application to flue gases without SO_x such as from natural gas firing. However, alumina tends to react with SO_x, particularly SO_3, to form aluminum sulfate. This "poisons" the catalyst by decreasing the available surface area and the catalyst activity. Titanium dioxide and silica are less susceptible to attack by SO_3 and are applicable to flue gas from heavy oil or coal firing. The active metal on the substrate may include Co, Cr, Cu, Fe, Mn, Ni, Pt, and V or combinations thereof, but the exact composition of the catalyst is usually proprietary. These metals or their oxides can also react with the SO_x to form sulfates. Many of these sulfates are also catalytic in the reduction of NO with NH_3, and therefore, can be tolerated. The catalysts are normally designed to have a life of at least 1 year.[4,5]

The formation of ammonium sulfate and bisulfate is a major concern with SCR processes. Ammonium bisulfate will form downstream of the reactor if NH_3 and SO_3 are present in sufficient quantities and if the gas temperature drops sufficiently. It is very difficult to avoid the conditions for formation; for example, ammonium bisulfate will form if the gas contains 10 ppm of NH_3 and 10 ppm of SO_3 at a temperature of 210°C. Ammonium sulfate will form at lower temperatures. Fine particulate emissions of these compounds are a concern, but the major problem with ammonium sulfate and bisulfate is deposition on heat exchanger surfaces. Since these compounds are very corrosive and interfere with heat transfer, the heat exchanger must be made of corrosion resistant material and must be cleaned periodically by soot blowing or water washing. Approaches to preventing this formation entail use of an ammonia decomposition catalyst or operation at lower NH_3/NO ratios.[4,5]

Another concern with SCR processes is catalyst plugging. Significant progress has been made in avoiding plugging problems through reactor and catalyst design. Fixed bed reactors, such as parallel passage, tube, and honeycomb, are being designed which can tolerate particle loadings typical of coal firing. (Unless otherwise specified, the fixed bed reactors referred to in this paper will be this open passage type.) Moving bed reactors are also being developed which can tolerate and remove moderate amounts of particles.[4,5] However, the particle concentrations acceptable to a moving bed reactor are approximately an order of magnitude less than those tolerated by a fixed bed system. The space velocity through a moving bed reactor is expected to be about double that of a fixed bed reactor, but the pressure drop across the moving bed reactor should be less.

Published information on the cost of SCR processes is limited and estimates available are based on different design premises. The reported estimates of the required capital investment range from $10 to $80/kW with an average of about $30/kW. The revenue requirements range from 0.2 to 3.3 mills/kWh with an average of about 1.7 mills/kWh.[2,5]

A list of Japanese SCR process developers is given in Table I along with information on their developmental status. There are 16 commercial scale plants in operation treating 100,000 to 750,000 Nm^3/hr of flue gas (33 to 250 MW). In addition, there are 11 prototype plants treating from 15,000 to 99,999 Nm^3/hr of flue gas and numerous pilot and bench scale plants in operation.[6] The prototype and commercial scale plants are achieving 90% control of the NO_x from flue gas derived primarily from gas- and oil-fired sources. The operating experience in Japan qualifies NO_x control by SCR as a viable control technique in the U.S. when high NO_x removal efficiencies are required from gas- and oil-fired sources. SCR technology has not been demonstrated in Japan on coal-fired sources although several of the pilot plants are currently evaluating such an application and larger scale demonstrations are expected in the near future. In fact, a northern utility in Japan in considering installation of a 90 MW SCR system on a coal-fired boiler which will begin operation in 1980.[6]

Dry Simultaneous NO_x/SO_x Processes

There are two noteworthy variations of SCR processes which have the capability to simultaneously remove NO_x and SO_x: the activated carbon process and the Shell copper oxide process.

The activated carbon process requires a special carbon bed which acts as an adsorbent for SO_x and as a catalyst in the reduction of NO_x with NH_3. When the bed is saturated with SO_x, flue gas is switched to a fresh bed, the carbon is regenerated,

TABLE I. MAJOR NO_x SELECTIVE CATALYTIC REDUCTION PLANTS IN JAPAN[6]

Process Developer	Plant Owner	Plant Site	Capacity (Nm^3/hr)	Capacity (∼MW)	Source of Gas	Start-up
Asahi Glass	Asahi Glass	Keihin	70,000	23.3	Glass Furnace	Apr. 1976
Hitachi Ltd.	Kawasaki Steel	Chiba	350,000	116.6	Coke Oven	Oct. 1976
Hitachi Ltd.-Mitsubishi PC	Mitsubishi PC	Yokkaichi	150,000	50.0	Oil-fired Boiler	Dec. 1975
Hitachi Zosen	Toshin Steel	Himeji	70,900*	23.6	Heating Furnace	June 1976
Hitachi Zosen	Idemitsu Kosan	Chiba	350,000	116.6	CO-fired Boiler	Nov. 1975
Hitachi Zosen	Shindaikyowa P.C.	Yokkaichi	440,000	146.6	Oil-fired Boiler	Dec. 1975
Hitachi Zosen	Kawasaki Steel	Chiba	750,000	250.0	Sintering Machine	Nov. 1976
Japan Gasoline	Kashima Oil	Kashima	50,000	16.6	Heating Furnace	Nov. 1975
Japan Gasoline	Fuji Oil	Sodegaura	70,000	23.3	CO Boiler	Mar. 1976
Kurabo	Kurabo	Hirakata	30,000	10.0	Oil-fired Boiler	Aug. 1975
Mitsubishi H.I.	Fuji Oil	Chiba	200,000	66.6	Oil-fired Boiler	Late 1977
Mitsui S.B.-Mitsui P.C.	Mitsui Pet. Chem.	Chiba	200,000	66.6	Oil-fired Boiler	Sep. 1975
Mitsui S.B.-Mitsui P.C.	Ukishima Pet. Chem.	Chiba	240,000	80.0	Oil-fired Boiler	Aug. 1976
Mitsui Toatsu	Mitsui Toatsu	Takaishi	170,000*	56.6	Ammonia Plant	Oct. 1976
Mitsui Toatsu	Mitsui Toatsu	Takaishi	87,000*	29.0	Ammonia Plant	Mar. 1976
Mitsui Toatsu	Osaka Pet. Chem.	Takaishi	90,900*	30.3	Heating Furnace	Sep. 1976
MKK-Santetsu	Nippon Yakin	Kawasaki	15,000	5.0	Oil-fired Boiler	June 1976
Osaka Gas	Osaka Gas	Sakai	63,800*	21.3	Gas Generator	July 1976
Seitetsu Kagaku	Seitetsu Kagaku	Kakogawa	15,000	5.0	Oil-fired Boiler	June 1975
Sumitomo Chemical	Sumitomo Chem.	Sodegaura	30,000	10.0	Oil-fired Boiler	July 1973
Sumitomo Chemical	Sumitomo Chem.	Anegasaki	100,000*	33.3	Gas-fired Boiler	Feb. 1975
Sumitomo Chemical	Higashi Nihon Met.	Sodegaura	200,000*	66.6	Heating Furnace	May 1974
Sumitomo Chemical	Sumitomo Chem.	Anegasaki	200,000*	66.6	Gas-fired Boiler	Feb. 1975
Sumitomo Chemical	Sumitomo Chem.	Niihama	200,000*	66.6	Heating Furnace	Mar. 1975
Sumitomo Chemical	Nihon Ammonia	Sodegaura	250,000*	83.3	Heating Furnace	Mar. 1975
Sumitomo Chemical	Sumitomo Chem.	Sodegaura	250,000	83.3	Oil-fired Boiler	Mar. 1976
Sumitomo Chemical	Sumitomo Chem.	Sodegaura	300,000	100.0	Oil-fired Boiler	Oct. 1976

*Flue gas contains minimum amounts of SO_x and particles and a concentrated SO_2 stream is produced which can be used to generate a salable byproduct. The process has the potential for removing 90% of both pollutants, but its application may be limited to flue gas containing relatively equal concentrations of NO_x and SO_x.[4] The economic projections for the process are about $65/kW for the capital investment and 6.3 mills/kWh in revenue requirements. The activated carbon process is being evaluated on a pilot plant scale in Japan by Takeda, Unitika, and Sumitomo Heavy Industries.[5]

In the Shell process, copper oxide reacts with SO_2 to form copper sulfate. The copper sulfate and, to a lesser extent, the copper oxide act as catalysts in the reduction of NO_x with NH_3. As in the activated carbon process, a multiple bed system is required so that a bed is available for acceptance while regeneration takes place. In the regeneration cycle, hydrogen is used to reduce the copper sulfate and a concentrated SO_2 stream is produced which can be used to generate a salable byproduct.[4] The economic projections for the process are $131/kW for the capital investment and 5 mills/kWh for the revenue requirements.[5] The process has been installed at the Showa Yokkaichi Sekiyu Company (SYS) plant in Yokkaichi, Japan on a commercial scale (120,000 Nm^3/hr) and has removed 90% of the SO_x and 70% of the NO_x.[4]

WET PROCESSES

The following wet process types are being developed:

Oxidation-Absorption Processes
Absorption-Oxidation Processes
Oxidation-Absorption-Reduction Processes
Absorption-Reduction Processes

Wet NO_x Processes

The first two process types are generally for NO_x control only. In oxidation-absorption processes, the relatively insoluble NO is oxidized in the gas phase to NO_2 which is absorbed into the liquid phase. The typical oxidizing agents used are ozone and chlorine dioxide. The absorbents vary with process developer. The process seems more feasible for flue gas containing equimolar mixtures of NO and NO_2 which is not typical of combustion flue gas. Much of the absorbed NO_2 remains in the liquid phase in the form of nitrate salts which are water pollutants.[4]

In absorption-oxidation processes, NO is absorbed directly into the liquid phase and then oxidized. Liquid oxidizing agents such as sodium hypochlorate or hydrogen peroxide are used to convert the NO to a nitrate salt. Due to the insolubility of NO, relatively large absorbers are required. In addition, the process is not applicable to flue gas containing SO_2 since the more soluble SO_2 would consume the liquid oxidizing agent by converting the absorbed sulfite ion into sulfate.[4]

Due to their complexity, limited applicability, and water pollution problems, wet processes cannot compete economically with dry selective catalytic reduction processes for control of NO_x in combustion flue gas. Therefore, these process types will not be addressed further in this paper, but additional information is available from other sources.[2,3,4,5]

Wet Simultaneous NO_x/SO_x Processes

The attractiveness of wet processes is their potential for simultaneous removal of NO_x and SO_x. Oxidation-absorption-reduction processes and absorption-reduction processes are designed for this type of control.

The oxidation-absorption-reduction processes basically evolved from flue gas desulfurization (FGD) systems. A gas phase oxidant is injected before the scrubber to convert NO to the more soluble NO_2. The NO_2 is then absorbed into an aqueous solution with SO_2. The absorbent varies with the type of FGD system being modified. The absorbed SO_2 forms a sulfite ion which reduces a portion of the absorbed nitrogen oxides to molecular nitrogen. The remaining nitrogen oxides are removed from the waste water as nitrate salts. The remaining sulfite ions are oxidized into sulfate by air and removed as gypsum. The percentage of nitrogen oxides going either to the preferred molecular nitrogen or to the troublesome nitrate salts is uncertain; however, it is estimated to be about 50-50, but this can vary considerably.[4]

The oxidation-absorption-reduction processes have the potential to remove 90% of both SO_x and NO_x from combustion flue gas.[4] However, there are several drawbacks remaining to be overcome before the processes can be widely applied. The process chemistry is complex and use of a gas phase oxidant, such as ozone or chlorine dioxide, is expensive. Chlorine dioxide, although cheaper than ozone, adds to the waste water problems created by the nitrate salts. Chlorine dioxide also causes concern due to the possibility for chlorination of organics in the waste water to produce carcinogenic compounds.

Despite these drawbacks, the potential of a simultaneous removal process warrants further research and development. Table II lists the process developers evaluating oxidation-absorption-reduction technology. One small commercial scale plant (33 MW), four prototype, and three pilot plants are currently being operated in Japan.[6] As with SCR processes, published economic data are limited, but the average reported capital investment is about $110/kW and the average revenue requirement is about 7.5 mills/kWh.[5]

The absorption-reduction processes were seemingly developed to avoid the use of a gas phase oxidant. A chelating compound, such as ferrous-EDTA (ethylenediamine tetraacetic acid) which has an affinity for the relatively insoluble NO, is added to the scrubbing solution. The NO is absorbed into a complex with the ferrous ion and the SO_2 is absorbed as the sulfite ion. The NO complex is reduced to molecular

TABLE II. MAJOR WET NO_x/SO_x CONTROL PLANTS IN JAPAN[6]

Process Developer	Plant Owner	Plant Site	Capacity (Nm^3/hr)	Capacity (MW) Approx.	Source of Gas	Start-up
OXIDATION - ABSORPTION - REDUCTION PROCESSES						
Chiyoda	Chiyoda	Kawasaki	1,000	0.3	Oil-fired Boiler	Aug. 1973
Ishikawajima H.I.	Ishikawajima H.I.	Yokohama	5,000	1.6	Oil-fired Boiler	Sep. 1975
Mitsubishi H.I.	Mitsubishi H.I.	Hiroshima	2,000	0.6	Oil-fired Boiler	Dec. 1974
Osaka Soda	Osaka Soda	Amagasaki	60,000	20.0	Oil-fired Boiler	Mar. 1976
Shirogane	Mitsui Sugar	Kawasaki	48,000	16.0	Oil-fired Boiler	Aug. 1974
Sumitomo Metal-Fujikasui	Sumitomo Metal	Amagasaki	62,000	20.6	Oil-fired Boiler	Dec. 1973
Sumitomo Metal-Fujikasui	Toshin Steel	Fuji	100,000	33.3	Heating Furnace	Dec. 1974
Sumitomo Metal-Fujikasui	Sumitomo Metal	Osaka	39,000	13.0	Oil-fired Boiler	Dec. 1974
ABSORPTION - REDUCTION PROCESSES						
Asahi Chemical	Asahi Chemical	Mizushima	600	0.2	Oil-fired Boiler	Apr. 1974
Chisso Corp.	Chisso P.C.	Goi	300	0.1	Oil-fired Boiler	Apr. 1974
Kureha Chemical	Kureha Chemical	Nishiki	5,000	1.6	Oil-fired Boiler	Apr. 1975
Mitsui S.B.	Mitsui P.C.	Chiba	150	0.05	Oil-fired Boiler	Apr. 1974

nitrogen by reaction with the sulfite ion. A regeneration step recovers the ferrous chelating compound and oxidizes the sulfite ion into sulfate which is removed as gypsum.[5]

The absorption-reduction processes also have the potential to remove 90% of both the NO_x and SO_x in combustion flue gas.[4] Although the processes seem to have advantages over the oxidation-absorption-reduction processes, there are obstacles to be overcome before the processes can be widely applied. Even with the addition of the chelating compounds, a large absorber is required to absorb the NO. The replacement, recovery, and regeneration costs of the chelating compounds, although potentially less than the gas phase oxidants, are still significant. The process chemistry is complex and is sensitive to the flue gas composition of SO_2, NO_x, and oxygen. The molar ratio of SO_2 to NO_x must remain above approximately 2.5 and the oxygen concentration must remain low.[5]

Table II also lists the process developers evaluating absorption-reduction technology in Japan. There are four pilot or bench scale plants currently being operated.[6] The average reported capital investment is about $96/kW and the revenue requirements are about 6.3 mills/kWh.[5]

Table III summarizes the status, cost, and performance of the dry and wet processes for control of NO_x and simultaneous control of NO_x and SO_x.

CONTROL OF NO_X, SO_X, AND PARTICLES

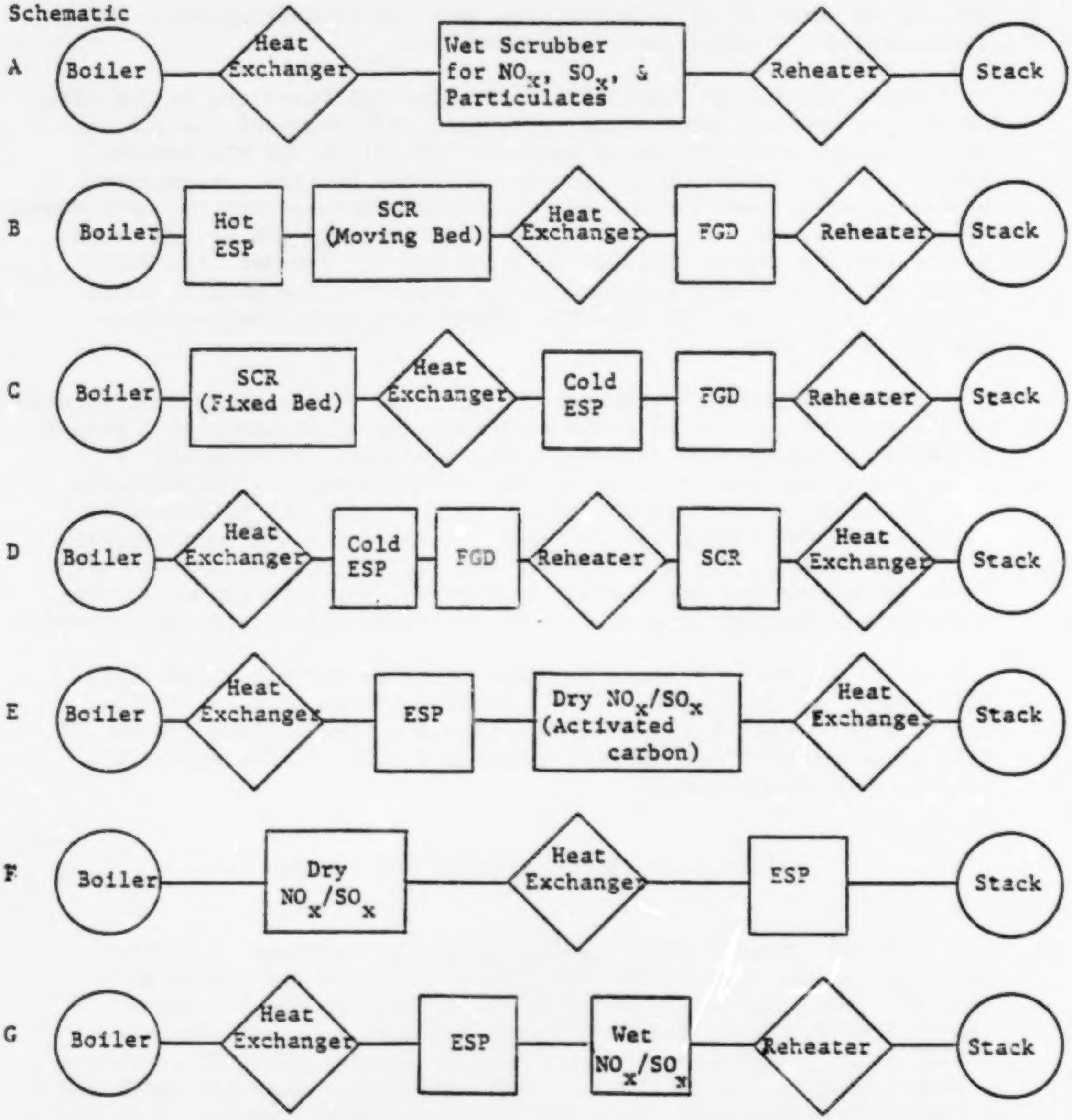
Over 90% control of NO_x, SO_x, and particles may eventually be required in the U.S. for stationary combustion sources, especially for new, large, coal-fired sources. Schematics of some of the alternatives for such an overall control system are shown in Figure 1.

Perhaps the ideal situation would be represented by one control device that simultaneously removes NO_x, SO_x, and particles. Such a control device is not yet available, but it is conceivable that a wet scrubber system could remove all three pollutants. Such a system is represented in Schematic A of Figure 1. Since the recovery of heat from the flue gas is important, a heat exchanger is shown in the schematic. A reheater is also shown since most wet scrubber systems require reheat of the flue gas prior to its discharge from the stack.

The most developed overall control system is NO_x control by selective catalytic reduction (SCR), SO_x control by flue gas desulfurization (FGD), and particle control by an electrostatic precipitator (ESP). The sequence of these control devices is variable as illustrated in Schematics B, C, and D. Schematic B shows particle control first, followed by NO_x control, and then SO_2 control. In this configuration, the SCR system could be a moving bed type which would require most of the particles to be removed first. To maintain high

TABLE III. STATUS OF FLUE GAS TREATMENT PROCESSES IN JAPAN

Process Type	Developmental Plants	Removal Efficiency (%) NO_x	SO_x	Approx. Capital Cost ($/kW)	Approx. Revenue Requirements (mills/kWh)
Dry Selective Catalytic Reduction (with ammonia)	16 commercial 11 prototype	$\geq$ 90	N.A.	30	1.7
Dry Simultaneous NO_x/SO_x					
Activated carbon	3 pilot	$\sim$ 90	$\sim$ 90	65	6.3
Shell Copper Oxide	1 commercial	$\sim$ 70	$\sim$ 90	110	5.0
Wet Simultaneous NO_x/SO_x					
Oxidation-absorption-reduction	1 commercial 4 prototype 3 pilot	$\leq$ 90	$\geq$ 90	131	7.5
Absorption-reduction	4 pilot or bench	$\leq$ 90	$\geq$ 90	96	6.3


Schematic
A
Boiler
Heat Exchanger
Wet Scrubber for NO_x, SO_x, & Particulates
Reheater
Stack
B
Boiler
Hot ESP
SCR (Moving Bed)
Heat Exchanger
FGD
Reheater
Stack
C
Boiler
SCR (Fixed Bed)
Heat Exchanger
Cold ESP
FGD
Reheater
Stack
D
Boiler
Heat Exchanger
Cold ESP
FGD
Reheater
SCR
Heat Exchanger
Stack
E
Boiler
Heat Exchanger
ESP
Dry NO_x/SO_x (Activated carbon)
Heat Exchanger
Stack
F
Boiler
Dry NO_x/SO_x
Heat Exchanger
ESP
Stack
G
Boiler
Heat Exchanger
ESP
Wet NO_x/SO_x
Reheater
Stack

ESP - Electrostatic Precipitator for Particle Control
FGD - Flue Gas Desulfurization for SO_2 Control
SCR - Selective Catalytic Reduction for NO_x Control

FIGURE 1 - POTENTIAL EQUIPMENT CONFIGURATION FOR NO_x, SO_x, AND PARTICLE CONTROL

temperatures needed by the SCR system, a hot-ESP would be necessary. The requirement for a hot-ESP could be avoided by use of a fixed bed SCR system which could tolerate high particle concentrations. This configuration is illustrated in Schematic C.

Since the sulfur compounds in the flue gas lower the resistivity of the fly ash and improve the collection efficiency of the ESP, it is not deemed advantageous to have the ESP follow the FGD system. However, it is uncertain if ammonia, ammonium sulfate, or ammonium bisulfate will leave the SCR system and adversely affect the performance of the FGD system. To avoid this possibility, the SCR system could follow the FGD system as shown in Schematic D. However, the disadvantage of this configuration is the extensive reheat that would be required to raise the flue gas temperature to a level suitable for the SCR system.

The simultaneous NO_x/SO_x systems present an apparent simplification of the control systems as shown in Schematics E, F, and G of Figure 1. Schematic E depicts the activated carbon process and Schematic F illustrates the Shell process for dry simultaneous NO_x/SO_x control. Two configurations are presented due to the different tolerance of particle concentrations and to the different operating temperatures of the processes. The wet simultaneous NO_x/SO_x control systems are shown in Schematic G and can be represented by either the oxidation-absorption-reduction processes or by the absorption-reduction processes.

At this time it is mere speculation as to which configuration will emerge as the optimum overall control system from a technical and economic standpoint. In all probability, the optimum system will be dependent on specific flue gas and site considerations as well as user preference.

EPA'S NO_X FLUE GAS TREATMENT PROGRAM

High NO_x removal efficiencies may not be required to achieve and maintain the current National Ambient Air Quality Standards (NAAQS). Further, the current New Source Performance Standards (NSPS) for NO_x can be achieved by implementation of combustion modification techniques which are more economical than FGT processes. However, there are significant factors which may cause the NAAQS and the NSPS to become more stringent. These include: the alarming increase in NO_x emissions from stationary combustion sources projected for the next decade, the possibility of a short-term NO_2 NAAQS, the relationship of NO_x emissions to levels of photochemical oxidants, the impact of increased use of coal resources, the impact of relaxing mobile source emission standards, the role of NO_x emissions as precursors to other pollutants of concern such as PAN (peroxyacyl nitrates), other nitrates, nitrosamines, and nitric acid, and the health effects of NO_x and related pollutants.

If more stringent standards are promulgated, then NO_x FGT technology may be required to meet the standards to protect human health and welfare. Therefore, the NO_x FGT program is proceeding with experimental projects progressing toward full scale demonstration of highly efficient NO_x and simultaneous NO_x/SO_x control technology in parallel with control strategy and technology assessment studies. The results of these studies will assist in determining the appropriate scale of the experimental projects. EPA's past, current, and planned activities in these areas are summarized below.

CONTROL STRATEGY AND TECHNOLOGY ASSESSMENT STUDIES

The control strategy and technology assessment studies are mainly research projects to examine various aspects of NO_x control technology and to determine if and when NO_x FGT technology will be needed in the U.S.

Assessment of Japanese Technology

Since Japanese technology in this field is more advanced than any other country's, EPA has sponsored the publication of periodic reports and papers to facilitate the transfer of information on NO_x and NO_x/SO_x abatement technology from Japan. These documents have been mainly prepared by Dr. Jumpei Ando of Chuo University in Tokyo, Japan.[2,3,4,7,8] Dr. Ando is also assisting EPA in activities associated with the Stationary Source Pollution Control Project of the US/Japan Environmental Agreement which includes a subproject on NO_x and NO_x/SO_x FGT technology.

In addition to monitoring published information from Japanese sources, EPA personnel have made periodic trips to Japan to observe testing facilities and to discuss the technology with process developers and operating personnel. The most recent trip was in March 1977.

Ozone Oxidation of NO[9]

Gas phase oxidation of NO to NO_2 is essential for wet oxidation-absorption-reduction processes. Therefore, a task order was issued by IERL-RTP to the Research Triangle Institute to analyze the supply, demand, production economics, and energy consumption of this key FGT process step. The results of the study indicate that only a stoichiometric amount of ozone is required to achieve essentially complete conversion of NO to NO_2 which may be subsequently scrubbed from the gas stream.

The energy requirements and the capital and operating costs were examined for ozone generation with both air and oxygen as input to the ozone generator. Approximately 13% more energy is required for ozone generation from oxygen than from air. The capital investment for ozone generation from oxygen is about 3 times as large as that required from air, and operating costs are about twice as large. For a 500 MW plant with air as input to the ozone generator, the estimates for oxidizing 200 ppm of NO were: energy requirement, 1.1×10^8 kWh/yr or 3.1% of station capacity; capital investment, \$17.60/kW; and operating costs, 2.0 mills/kWh. The 200 ppm concentration is representative of a coal-fired source with combustion modification techniques applied or an oil-fired source without supplementary NO_x control applied. The estimates are for oxidation of NO only; the energy requirements and cost of control for NO_2 would be additive.

The report indicates that unless there is a significant improvement in ozone generation technology, wet processes using ozone for oxidation of NO to NO_2 will be very expensive. However, since these processes have potential for simultaneous NO_x/SO_x control, the energy and cost impacts may be more acceptable.

NO_x Control Strategy Assessment

IERL-RTP contracted with Radian Corporation to determine the potential effectiveness of applying NO_x controls to large stationary combustion sources. The Chicago Air Quality Control Region (AQCR) was selected for a modeling study of emissions from point, area, and mobile sources to determine the relative impact of each category on ambient NO_x concentrations. The calibrated dispersion model predictions of annual average concentrations indicate that the major point sources, which contributed nearly 40% of the total NO_x emissions in Chicago, accounted for less than 10% of the ambient NO_2 levels in 1974. Preliminary investigation of expected short-term concentrations of total NO_x shows that major point sources may contribute as much as 80% of measured NO_x levels. Therefore, it appears that stringent NO_x control for large point sources may be required to meet a potential short-term NO_2 standard, but cannot be justified currently on the basis of the existing annual average NO_2 standard.[10] However, NO_x emissions from stationary combustion sources are expected to increase significantly in the next decade. As a result of these findings, the Chicago AQCR modeling study was expanded to determine more accurately the short-term ambient NO_2 levels, to project the annual and short-term NO_2 concentrations to 1985, and to assess the use of NO_x emission control on stationary combustion sources to attain or maintain compliance with possible NO_2 ambient short-term and annual average standards. The results of this study should be available by early 1978.

Another Radian Corporation study is seeking to determine the key factors relating to "if" and "when" NO_x FGT technology will be needed in the U.S. Since research and development of a technology should lead its application by several years, it is necessary to monitor factors which could require implementation of NO_x FGT technology in the near future. By these efforts, the decision to emphasize, maintain, or terminate the research, development, and demonstration of NO_x FGT technology can be made on the best available information. This study should also be available in early 1978.

Economic Assessments of NO_x FGT Processes

The Tennessee Valley Authority (TVA), through an interagency agreement with EPA, is developing comparative economics of NO_x and NO_x/SO_x FGT emission control processes. This state-of-the-art review will be conducted in two phases. Phase I will evaluate and summarize the technical feasibility of all candidate NO_x control processes being offered in the U.S. and Japan. The Phase I report, which includes descriptions of about 45 processes, should be published in the summer of 1977.[5] Phase II will concentrate on the most promising processes identified in Phase I and will perform a preliminary economic assessment of each, including development of material and energy balances. In addition, a direct comparison of the economic and technical feasibility of the dry and wet processes will be made to determine the most effective method to remove NO_x and SO_x from combustion flue gas. The project is cofunded by IERL-RTP and the Electric Power Research Institute.

EPA is planning a third phase of the project to prepare detailed economic projections of as many as four of the most promising processes. This activity should be complete in late 1978. Further, it is contemplated that a study will be conducted during this phase to determine the impact of ammonia utilization by SCR processes. The cost and energy requirements of ammonia generation for a typical utility application will be examined. In addition, the impact on the supply, demand, and cost of ammonia worldwide will be analyzed. This study may be available by the end of 1977.

EXPERIMENTAL PROJECTS

EPA's experimental projects have been directed toward enhancing the evolution of FGT technology from bench scale research to full scale demonstration on coal-fired sources by the mid-1980's. The technology must be applicable to utility and large industrial combustion sources and must achieve highly efficient NO_x and simultaneous NO_x/SO_x control in a relatively energy efficient and economical manner.

Bench Scale Catalyst Research[11]

In 1975, a research grant was awarded to the University of California at Los Angeles (UCLA), School of Engineering and Applied Sciences to further the development of promising catalysts. The study extended the catalyst screening work performed earlier by UCLA under an IERL-RTP contract with TRW, Inc.[12] The objectives of the grant were to optimize the compositions of vanadium and iron-chromium catalysts for selective reduction of NO_x with ammonia and to perform long-term durability studies of the optimum catalyst compositions in flue gas containing sulfur dioxide. The results of the study, completed in mid-1976, indicated that a 15% loading of vanadium oxide on alumina support material and a 10% loading of iron oxide-chromium oxide on alumina support material with an iron/chronium ratio of 9:1 were the optimum catalyst formulations.

Parametric tests showed that both catalysts were selective, in that only the NO_x was reduced. The tests also showed strong enchancement of NO_x conversion rates due to the presence of O_2 under typical operating conditions. CO_2, H_2O, and SO_2 did not affect the NO_x reduction in the concentration ranges applicable to power plant exhaust. Both catalysts were most active between 400°C and 425°C and required excess NH_3 for maximum activity. Long-term durability tests of both catalysts in the presence of SO_x indicated no degradation in catalyst performance. Typical conversion levels for the vanadium and iron-chromium catalysts operating at 400°C in simulated flue gas were about 90% and 80%, respectively, at 20,000 hr^{-1} space velocity. In addition, preliminary tests of iron-vanadium and iron-chromium-vanadium catalysts indicated 99% removal of NO_x from the simulated flue gas.

Pilot Plant Evaluation of Gas and Oil Firing[13]

In 1973, a contract was awarded to Environics, Inc. to evaluate the performance, reliability, and practicality of a SCR system with ammonia and a platinum catalyst on alumina support material. A pilot plant, treating a slipstream from an operating utility boiler, was designed, installed, and tested on gas and oil firing. Laboratory testing was conducted to supplement the pilot plant testing. Satisfactory results were found on gas-fired operation with 85-90% NO_x removal achieved for over 4000 hrs at a space velocity of 50,000 hr^{-1}. Results on oil-fired operation indicate that the catalyst system was not suitable for flue gas containing SO_x. The maximum NO_x removal efficiency achieved was 65% with the average only 50%. Fluctuation in flue gas temperature and catalyst plugging with soot and ammonium sulfate caused problems on oil-fired operation.

Pilot Plant Evaluation on Coal Firing

The next phase of the experimental program is evaluation of FGT processes on a coal-fired application. A request for proposal was issued in September 1976, and best and final offers are currently being evaluated. Contract award is anticipated by the end of September 1977. It is contemplated that two contracts will result from this procurement process. One will be for a pilot plant to evaluate removal of NO_x emissions, and the other will be to evaluate simultaneous removal of NO_x and SO_x. However, budgetary constraints and technical considerations may impact on the final decision in this regard.

The pilot plants must treat a flue gas volume equivalent to 0.5 MW and achieve a NO_x removal efficiency of 90%. For the simultaneous control of NO_x and SO_x, 90% removal of both pollutants must be achieved. The pilot plant projects will each consist of a 24 month program which will be conducted in four phases. Phase I includes the preparation of a detailed process design and an estimation of capital and operating costs for the pilot plant. Following erection of the pilot plant and mechanical acceptance testing in Phase II, the contractor will perform system start-up and debugging, parametric testing, and optimization testing over a wide range of flue gas conditions during Phase III. Phase IV provides for testing and evaluation of the plant during 90 days of continuous operation. It is currently anticipated that final reports will be published on the results of the pilot plant operations in early 1980. A project manual conveying the total concept of the proposed plant is planned for early 1978. In addition to these projects, there is the possibility of a pilot plant project being initiated in 1977 with the Tennessee Valley Authority.

The pilot plant projects will enable an assessment of the technical, environmental, energy, and economic aspects of applying NO_x and NO_x/SO_x FGT technology to the U.S. coal-fired situation. This information, in conjunction with the control strategy and technology assessment studies, will provide technical and budgetary direction and emphasis for EPA's NO_x and NO_x/SO_x FGT program.

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SESSION V - WHERE DO WE GO FROM HERE?

SESSION CHAIRMAN: VICTOR S. ENGLEMAN, SCIENCE APPLICATIONS, INC.

The papers in previous sessions have presented the foundation on which we stand and have supplied the building blocks to achieve clean combustion of coal. This closing session takes a look into the future in terms of policy, supply, and technology for direct coal utilization. It is clear from the conference thus far that precombustion, combustion, and postcombustion technologies will all be important in achieving "Best Available Control Technology" for coal utilization. The National Energy Plan will have a major impact on the overall energy picture and the incentives and requirements for coal combustion. Increased coal utilization will require increased supplies which will require new mines and increased capacity in the delivery system. New developments and improvements in technology will be required to achieve the likely environmental requirements in a technically and economically sound manner. The papers in this session focus on these three key areas in the future of clean combustion of coal.

Transcript of Talk on

THE NATIONAL ENERGY PLAN

by

C. William Fischer
Department of Energy
Washington, D.C.

August 5, 1977

I spoke to Jim Schlesinger a week ago today in connection with the job of putting together a planning mechanism for the new Department of Energy and he gave me some very succinct and terse guidance which I believe is particularly relevant to this conference and which is why I am more eager to come here and listen to you than to talk. He said, "You know I have been around Washington a little bit." I should say that Jim Schlesinger, now Secretary Schlesinger, is quite a remarkable guy. His nomination and confirmation for the job of first Secretary of Energy in less than one day must have set a speed record. Hearings on the nomination were held yesterday morning from 8:00 to 11:30, and in the afternoon the Senate voted to confirm. But there is another record here: This is the fourth cabinet-level agency Jim Schlesinger has headed in the last seven years. Prior to becoming the President's chief energy advisor, Schlesinger was Chairman of the Atomic Energy Commission, Director of the Central Intelligence Agency, and Secretary of Defense. Prior to that he was Assistant Director of the Bureau of the Budget which was his forst job in Washington. His directions to me the other day were very clear. He said that in the defense business and in some of the other places where he has worked, you make a decision on a project, you make some estimates about what it ought to cost to implement, and then you summon the four-star generals and you say this is what I want you to do, this is how much money you have to do it with, and you may also call in the president of North American Rockwell and say that if you do it for that amount within that time schedule this is what the fee will be, and if you don't make the time schedule or you don't make the performance standard, then the fee will be reduced accordingly, and away you go from there. That is exactly the opposite of what the Department of Energy must do. The Department, if it is going to do its job for the Nation, should set a broad policy framework of overall objectives and then determine, with the help of the people who are going to have to work with these energy problems, how to get from here to there. In setting the broad policy goals we should ask, "What is feasible?" The output of this department is not going to be a set of things or a set of widgets; it is going to be a set of decisions that have to be made by millions of consumers and thousands of leaders in the corporate structures and the Federal, State and local public institutions of this country. The Federal Government will not be able to design, develop, direct and implement this program as though it is in control

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of all, or even the majority, of the tools necessary to solve our energy problem. We are going to have to do an awful lot of listening, and we are going to have to do a lot of cooperative work with the people who have to make the programs work. I thought I would share these thoughts with you. It is a perspective that is far from messianic. Just the opposite; it is something that is, I think, a realistic recognition of what it will take to move this country toward more plentiful energy resources and away from the profligacy in the use of energy that we have come to know, in part because of our pricing policy. This basic philosophy of listening to the public, is particularly applicable to me. I am not an engineer; I am not an expert; I have no specialized knowledge of the technical parameters within which we must operate. That is why I said last night that after this conversation I would like to hear your recommendations on legislation to facilitate siting, both for nuclear and nonnuclear power.

As we begin our discussion this morning, it might be worth it to review the gravity of the situation that we face. The world community is now using about 60 million barrels of oil a day. We are increasing our demands for that scarce commodity each year by about 5 percent and we are just now loading the first tanker out of Alaska. The entire yearly Alaskan North Slope production, when at full yield, is going to be roughly equivalent to the world's increase in consumption over a period of nine months. The whole of Texas oil production would equal the world's increase in oil consumption for one year; total Saudi Arabian production is roughly equivalent to the projected net increase in world consumption over the next three years. World production can probably keep increasing for six to eight years. Sometime in the late 80's or early 90's, however, it won't go up much more. If we could hold the growth rate in world demand to five percent yearly, we would use all of today's proven reserves--notice I said proven reserve, not inferred, not potential--by the end of the next decade. There are lots of arguments about how much resource there is in the ground. Oil companies are making all kinds of noises that if you just gave them a little more incentive they could turn all inferred and potential reserves into proven reserves.

In that regard, I would like to talk about the general structure of the National Energy Plan, and, specifically, about this incentive question that has to do with basic pricing policy. Later, I would like to concentrate on the coal part of the program and give you an update on what the specific provisions were in the President's Plan, what the Ways and Means and the Commerce Committees have done to the regulatory and tax provisions, and what are the major issues pending for House floor resolution today, and I mean literally today, that could alter the Plan significantly. Then we will open it up to questions and discussion.

Alaskan flow, at maximum production, will equal about two years' growth in U.S. energy demands. If we don't act now, by 1985 we will be using about 33 percent more energy than we are using today and because we probably can't substantially increase domestic oil production, we will have to import twice as much oil. To give you a frame of reference, in 1970 we were paying $2.7 billion a year for imported fuels. By 1976 the cost of imports was $36 billion. In 1977 we expect to be paying $45 billion for oil imports by 1985. What are we doing about this? Before the National Energy Plan we were continuing merrily on our way.

We charted a twelve-month moving average of gasoline consumption in the United States. The chart shows that in August of 1973 we were consuming 6.6 million barrels of motor gasoline per day. By August of 1975 we were still using about 6.6 MMB/D but this statistic reflected the period of the 1973-74 embargo when there were physical restrictions on supply, long lines for gasoline and so on. By June of 1977 this country was consuming 7.1 million barrels of gasoline per day. Since June of 1975 we have been increasing consumption at the rate of 3.8 percent a year. Production rates,on the other hand, have decreased. Another twelve-month moving average for production shows that in August of 1973 this country was producing 9.3 million barrels of crude per day. By June of 1977 production was down to 8 million barrels per day--the equivalent to a decreasing rate of 3 percent per year over the past two years. In January of 1973 we were importing 4.8 million barrels a day; by January of 1977, 7.5 million barrels a day--a rate of increase of 17.2 percent per year since June of 1975. The Administration's program consists of more than 150 specific provisions which are now moving through the United States Congress faster than I have ever seen any bill of that size, on any subject, move. Earlier this week I was engaged in a public television discussion with Representative Jim Jones from Oklahoma and the Moderator commented that in April when the President gave his message there was much concern expressed, but that now things have quieted down and there seems to be an energy gap in the Congress. Well, the first thing I did was to deny that. I had never seen such a sustained level of intense Congressional inquiry, debate, and activity. It may be that the coincidence of the timing of the National Energy Plan hitting the Congress and the Speaker's dedication to getting control of the House of Representatives may have facilitated fast action on the bill. I don't agree with this interpretation of the reasons for this speedy consideration of the bill by the House. I think Congress is exhibiting genuine interest in the energy problem. But the road is not smooth.

We have some of our greatest problems in the coal area--which perhaps reflects the technical difficulties we encounter in this area and the difficulties that have been discussed here in balancing our enhanced concern for the environment with our consciousness that we have to move at least in the intermediate term to more plentiful sources of energy. In some cases these difficulties can be resolved together--their solutions are not mutually exclusive nor inconsistent. I am thinking specifically of automobile emissions. It now looks as though going to cleaner tailpipes may also get us more efficiency. Cutting down the size of automobiles, which our European friends have seen fit to do for quite some time, actually accomplishes both goals simultaneously. But there are plenty of areas where we have very real and difficult technical problems to solve. You are in a position to help find some of the solutions. Beyond finding solutions to technical problems, some necessary compromises will have to be made to get us where we need to go in terms of balancing our need to burn coal, for instance, and our desire to protect the environment.

The Administration's program is basically four-pronged. First, we must have adequate price incentives to produce additional resources without undue enrichment. That is the guts of the new pricing policy which says that we are going to try to get the price of scarce fossil fuels up to their replacement value without causing undeserved windfall gains to producers. The mechanism for avoiding windfall gains to producers will be a tax coupled with a rebate to consumers to help compensate for higher fuel prices. There is room for disagreement on whether or not feeding these taxes that are imposed on the higher prices at the pump back to the consumer will in fact put a demand restraint in the system. It remains to be seen whether prices together with the rebate will have the full effect of reducing consumption. I believe that it will, because people react to their immediate consumption patterns and if they have a rebate in the future, they will not necessarily spend it on fuel. The second prong of the National Energy Act is the strong incentive to conserve without an unfair burden on the consumer. Adequate price incentives for production and correspondingly higher prices are the front part of this element of the plan. Prices will go up for both natural gas and oil--especially for new production, at the margin. We define "new" production in terms of where the well is drilled with regard to an already-existing producing well--at which depth and at what distance in relation to that last producing well. In case of gas, the Administration has agreed to a new reservoir concept, the details of which are yet to be worked out. And prices for those "new" commodities will be essentially uncontrolled. Theoretically, they would go to the world price. Additionally, residential, commercial and industrial consumers would be encouraged to conserve through adopting energy efficiency measures, such as retrofitting homes and businesses. Tax credits are provided for this purpose. Third are the proposals for strong incentives to use more abundant fuels, that is, the conversion program and the development of safe nuclear energy. Fourth is the vigorous research and development program on new and renewable energy resources.

With regard to the incentives for oil production, one of the proposals, known as the Jones-Schroeder Amendment, would allow producers a tax break against their well-head tax due. The credit would equal one-half a percent a month for each month for which exploration expenditures exceeded 25 percent of gross revenues. At the end of the first year the credit would equal 6 percent of the well-head tax due. This amendment which the Administration opposed was defeated yesterday on the floor of the House. The reason I am discussing the amendment is because it goes right to the heart of the major producer's case--that there are inadequate incentives for exploration and that more incentives are needed to develop new fields. First the plow back would be in addition to proposals that are in the President's bill to put secondary and tertiary enhanced recovery at the world price and all newly discovered oil at the world price by 1980, plus adjustments to account for the domestic rate of inflation. It is also in addition to the Administration's provisions that would allow domestic producers to receive a greater-per-barrel margin than producers any place else in the world. We surveyed the different world markets and found that with the world price being set on new oil production, domestic producers would receive a greater-per-barrel margin than they would any place else in the world including the North Sea and other fields. The Ways and Means Committee estimated that the Jones-Schroeder proposal would increase oil industry revenues by $89 million in 1978; we estimate that the amendment would result in an oil industry revenues increase of up to $100 million. If the tax break is made to be cumulative, then, by the end of 1980, the plow back would increase the oil industry's revenues by about $2 billion and $5.2 billion by the end of 1985.

Another problem with the Jones-Schroeder proposal is that the 25 percent threshold is so low the producers would be rewarded for doing something that they are doing already. According to the Bureau of the Census 1975 Annual Survey of Oil and Gas, independent producers were already reinvesting 63 percent of their revenues, apart from royalty revenues which account for 12 percent of their total revenues, for exploration and development. If you make the adjustment for royalty oil you are still above the 25 percent threshold. In 1975 the majors--the top eighteen oil producers--were reinvesting 35 percent of their revenues.

Additionally, the plow back would cause considerable administrative difficulties since it would be based on taxes and consequently the crude oil equalization tax would have to be levied on producers rather than first purchasers as was proposed in the Administration bill. Taxes would have to be collected from over 1600 producers rather than refiners and other first purchasers of which there are about 300. Furthermore, the cash balances that the major producers will have without the plow back after their investment in exploration and development is adequate. These funds are, of course, not excess profits. They are funds for use in other business purposes; they are essential to the business enterprise. They can be resources for alternative investments, or can be paid out to shareholders as dividends. But these are funds that could be used for additional investment for exploration and development which are not being so used. These producer cash balances amounted to $2 billion in 1972 and went up to $4.9 billion in 1975.

Still another problem is that the credit is available only to producers of flowing oil. A producer has to be established to have the 25 percent threshold ascertained. New entrants to the field would not be able to earn the credit. Major oil companies--the top 18--own two-thirds of all old domestic oil for which the plow back would be available, and, therefore, the majors would benefit the most. The reported domestic profits of the largest 18 oil companies increased from $3.5 billion in 1972 to $5.7 billion in 1975--a 60 percent increase in reported profits. Profits for 1975 were second only to 1974 profits in the history of the industry. Almost all of this increase in income comes from domestic rather than foreign production.

The government is currently quite limited in its ability to examine the industry profit structure. The Administration has put forward a proposal, authorized under existing law and mandated under the Department of Energy Organization Act, to improve the financial reporting by major producers. The major producers are not averse to the proposed Petroleum Company Financial Reporting System--they recognize that they have credibility problems.

Capital investment in development and exploration has increased in recent years. The average annual level in the early 1970's was about $9 billion a year; the actual spending in 1975 was $21.7 billion. In February of this year the Oil and Gas Journal projected that 1977 expenditures for development and exploration would be up to $26.7 billion. The sum total of this evidence leads us to believe that the profits are up, the investments are up, and the physical activity is up with regard to exploration and development without price decontrol. That gets us back to the question of whether the degree of enrichment that would result for producers from decontrol and the rise in prices to consumers, which the producers themselves are advocating, is necessary to stimulate exploration and development activity. We think there is reason to question the producers' arguments. With regard to physical activity, the number of rotary rigs in operation within the U.S., including Alaska, offshore, and the outer Continental Shelf, has increased significantly. In 1968, out of 2100 total rigs, 1500 were active and 600 were inactive. In 1972 the numbers dipped to about 1400 active, and the total number of rigs dropped to about 1760. By 1976 the total number of rigs was back up to 2200. There are now almost 2000 active rigs. The number of existing but inactive rigs is down to 225. About 90 percent of the total gas and oil rigs were active as of 1976. I've seen these figures in the annual rotary rig census of the Reid Tool Company. Hughes Tool does a similar census and they have some more recent numbers. Their figures indicate that the number of rigs active in 1977 is also around 1900 to 2000. So exploration and development activity is up and the number of inactive rigs is significantly down. And this is all prior to the President's policy under which new oil goes to the world price and new reservoirs go to the world price all of which makes for additional incentives. By the way, 2½ miles from a currently producing well is not a great distance in determining what is so-called new gas and oil.

In spite of all this activity, however, additions to reserves have declined, and proven reserves have dropped by 12 percent since 1972, to a proven domestic reserve level of 30.0 billion barrels at the end of 1976. What has happened is that as the prices have risen, and they have risen substantially even under the controlled situation, we have made wells in fields that were earlier passed over. Instead of stepping out into new reserves and new pools, producers are going back and opening up previously uneconomic reserves that don't expand our reserve. As it turns out there is also no significant effect on production--domestic oil production is continuing to fall. So this raises the question whether higher prices do yield significant additional production. For gas there have been increases in intrastate prices from 1970 averaging about 25¢ per Tcf to $1.30, to $1.97 and in some intrastate cases to above $2.00 (in some new contracts in parts of Texas and Louisiana) and interstate increases from 35¢ to an average of $1.21 per Tcf in 1976. Gas well drilling is today more than twice the level it was in 1971, but again proven reserves have shrunk by over 25% from the 1967 high of 293 trillion cu ft.

A few words about the oil and gas replacement program or the so-called coal conversion program. The proposal has two pieces and affects two major sectors. The pieces are the regulatory and the tax provisions. They affect major fuel-burning industries as well as utilities. I will discuss the regulatory proposals and what has happened to them in the Congress. Our regulatory proposals would cover industries and utility units capable of consuming fuel at a fuel heat input rate of 100 million Btu per hour or greater or a combination of several such units which have a total capability of consuming fuel at a fuel input rate of 250 million Btu's per hour or greater. In industry it includes boilers, combustors, combined cycle units and internal combustion engines. I am going to go through these provisions and tell you what the principal committees in the House, where the action is right now, have done to those provisions. But before I begin, to give you some perspective, the total amount of oil imports that the President's program would save is 4½ million barrels a day. Total U.S. consumption of oil in 1976 was 17.4 million barrels a day. Of that 17.4 MMBD consumed in 1976, our imports were 7.3 million barrels a day. If we don't do anything, by 1985 our oil imports will go to 11.5 million barrels a day. Under the President's program, imports would level off at 7.1 to 7.2 MMBD which means about a 4.5-million-barrels-a-day savings. Of that, 2.2 million barrels a day or about 50 percent is to be achieved through the oil and gas replacement program.

The House Commerce Committee, which has jurisdiction over the regulatory provisions has made a fundamental change in our proposal with regard to industry. The Committee bill excludes combustors from the proposed regulatory activity. If this provision is finally approved it will result in an oil savings loss of somewhere between 250 thousand barrels and half a million barrels a day for that provision alone. Under the President's bill no oil and gas will be burned by new utilities. Exceptions are made for environmental site limitations. Existing utilities will not be allowed to burn gas after 1989. If a utility is coal-capable it will be ordered to switch to coal. If it is not coal-capable it can be ordered to shift from gas to oil. The Commerce Committee version deletes this last provision. The Administration proposal makes exceptions for existing utility units based on environmental grounds or site limitations or the use of synthetic fuels. With regard to new industrial units no oil or gas may be used for boiler fuel. Nonboiler installations may also be prohibited by regulation or order from using oil or gas. Once again, exceptions will be made based on site limitations, environmental grounds, or technical impossibility. The House Committee has made no change in these provisions and they are up for a vote on the floor of the House today. Existing industrial units which are coal-capable may be prohibited by regulation or order from using oil or gas. If they are capable of using mixtures or combinations of fuels, they may be ordered to use the minimum possible amounts of oil or gas. Exceptions here also are based on site limitations, environmental grounds or technical impossibility.

I should also discuss briefly the tax provisions. On the industry side there would be a single tax rate effective in 1979 at a level of 90¢ a barrel for oil used starting in 1979 and would phase up to $3 a barrel for oil used in 1985, adjusted for inflation. Effective in 1979 gas used would be taxed at a rate equal to the difference in Btu equivalent price between gas and distillate fuel minus $1.05 per million Btu of gas used during that year. The $1.05 deduction phases out, so that by 1985 the tax will equal the difference in price between gas and Btu equivalent distillate. The Ways and Means Committee went from a one-tier tax provision and made a distinction between the tax rate for boilers, turbines and other internal combustion engines, and other nonexempt industrial users, mostly coal-capable nonboilers. The Committee also basically reduced the initial tax from 90¢ (in the case of industrial oil) to 30¢ a barrel, but phasing up to the same $3 a barrel by 1985. These reductions in taxes are estimated to lose, in terms of oil saved, another half a billion barrels of oil. Industries and firms using more than 500 billion Btu's or 85,000 barrels of oil equivalent a year--accounting for less than 2 percent of the total number of industrial firms or about 1400 out of 100,000 firms-- will be taxed under these provisions.

The Ways and Means Committee included an exception from this tax for process use of oil or natural gas if other fuels are not usable for technical, economic or environmental reasons. The Administration's proposal, as well as in the Ways and Means proposal, made exceptions for transportation including aircraft, rail and water, farming, ammonia feedstocks, refining, automotive or special fuels, and for gas that is reinjected for the extraction of additional gas. The Ways and Means Committee added exemptions for residential facilities, commercial facilities, and any facilities not an integral part of manufacturing, processing or mining. Additionally, Congressman Steiger introduced an amendment in the Ways and Means Committee that would extend exemptions from the regulatory provisions for environmental and technical feasibility reasons to the application of the tax. The Administration's bill provided that, even though you might be exempt from the prohibition against using oil and gas, you would still have the tax imposed. The Steiger amendment would say that if you were exempt from the regulation you are also exempt from the tax. The Steiger amendment adds another loss in savings of barrels of oil a day. The Corman amendment that is up on the floor today would eliminate that additional exemption. Finally, the Ways and Means Committee has added two other exemptions to the bill. Industries that can show that they would be placed at a competitive disadvantage would be exempt. That adds up to another 100,000 barrels of oil a day. Another amendment provides a procedure whereby the Secretary would have discretionary authority to reclassify industrial uses of oil and gas to a lower tier tax rate or altogether exempt such uses from tax. That would add another loss in savings of a quarter of a million barrels a day.

With regard to the utility oil tax, the Administration proposed a 25¢ per million Btu or $1.50 a barrel flat tax beginning in 1983 but with inflation adjustments beginning on the date of passage. The Ways and Means Committee put a 25¢ a million Btu or $1.50 a barrel flat tax beginning in 1983, but with inflation adjustments beginning in 1981. The utilities gas use tax begins in 1983 and is keyed to the regional distillate price as a target. In 1983 the tax would be 50¢ a million Btu less than the target price. By 1988 it would be equal to the target price, that is, the regional distillate price. Inflation adjustments are made from 1975. Once again, the Committee would start the tax in 1983, initially at 55¢ per million Btu and going to 75¢ per million Btu in 1985. The tax can't exceed the regional residential gas prices and it is inflation-adjusted from a later date. This loses the additional one-half a billion barrels that I mentioned previously. All those additional amendments and exemptions reduce the 2.2 million barrels a day oil saving that is supposed to result from the coal conversion program to somewhere between .8 and 1.0 million barrels a day. The Administration's bill also contains a rebate program which is basically a tax exemption from this oil and gas use tax for investment in alternative energy properties, including boilers not using oil or gas, coal utilization equipment, low Btu gas control equipment, required pollution control equipment, but excluding buildings and structural components. The Ways and Means Committee added to that high-Btu-gas-from-coal equipment, up to the turbine stage, and for geothermal and hydroelectric power.

For utilities the rebate is the same as the industrial rebate in the Administration's bill except that in the case of the industry there is an alternative. They can either take the rebate or they can take an additional 10 percent investment tax credit on top of their existing 10 percent investment tax credit. This does not apply to utilities. The utility rebate is available only for investments that replace or convert existing oil- or gas-fired facilities. Industrial firms are not limited in the Administration's bill to conversion or replacement investments. The Ways and Means Committee provides that the rebate for utilities is also available for phasing down instead of only being available for the conversion and puts the incentive on phasing down and converting from base load to peak load use of oil- or gas-fired facilities. That also would mean a substantial loss in energy savings.

I would say that the major issue on the House side that is up for action today is the Corman-Steiger debate on whether the regulatory exemption should also apply to the taxes. The rationale here, of course, for allowing the tax to be imposed even when the regulations are not, is that you need a variable incentive to move people away from the use of oil and gas or to allow them, in the case of large firms--and these taxes only apply to large firms--to take advantage of being able to convert where they can convert, and pay the taxes where they choose not to convert or where they can't convert. Those taxes would then be recaptured for them in terms of their conversion investments on their units, because they can trade off inside the firm the taxes they pay on one unit with the rebates they get for the conversion of another unit.

I hope I have given you some idea of the importance of these provisions. I appreciated very much getting from you your suggestions on what the Federal government ought to do to facilitate this conversion to more plentiful sources of energy both in terms of its regulatory activities and the siting question and in terms of the technical activity in research and development.

THE OUTLOOK FOR COAL THROUGH 1985

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Although the Carter Administration has indicated that it is counting on coal to be the "swing fuel" which will allow us to reduce our dependence on imported oil, it has refused to come to grips with the real and potential barriers to the increased mining, transportation, and utilization of coal.

The future role of coal must be evaluated within the context of the total energy picture. While it is obvious that the United States needs a "comprehensive national energy policy," there has been little agreement as to what specific policies should be included in such a national energy policy. In general, industry had in mind a program which relied on the market forces of supply, demand, and price to allocate scarce energy resources among the various competing uses and to achieve desired fuel switching. However, as Walter Mead stated recently in an article in *Science*:

> ". . . to political Washington, the cry for a national energy policy is interpreted as a demand for more government decision-making and less reliance on the market."*

Mead further states that most professional energy economists have argued for less government and more reliance on the market to solve the "energy problem." This preference does not stem from a political conservatism as much as from their awareness of the "poor record of government interference in the energy market. *That record is one of massive and repeated resource misallocation*" (emphasis added).* The result of such an approach is that great emphasis is being placed on the "stick" and little on the "carrot." A "stick" policy which seeks to force certain actions which run counter to the internal economics of the energy user is likely to be met with strong opposition, while policies which seek to create economic incentives ("carrots") to switch fuels or to use energy more efficiently are much more likely to succeed. With these brief remarks as an introduction, I would now like to discuss the general factors underlying the markets for coal.

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*Mead, W. J., 22 July 1977, "An Economic Appraisal of President Carter's Energy Program," *Science*, vol. 197, p. 340.

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General Market Factors

Coal markets tend to be segmented by coal types. The primary segmentation of the market is between metallurgical and steam coals. Among the steam coals there is a further segmentation by coal types--bituminous, subbituminous, lignite, and anthracite. Each of these coals tends to serve special niches within the overall coal market. Some of the markets are much more constrained than others. Metallurgical coking coals are specialty coals which command premium prices. The demand for these coals is determined by the output of pig iron and steel, both here and abroad. The bulk of the coals exported overseas from the United States (excluding Canada) is of the metallurgical variety. Although there has been some movement of lower grade (high-volatile) metallurgical coals into the "compliance" steam coal* market in recent years, the markets for metallurgical and steam coals are essentially separate. Because the main growth sector over the next decade will be in the steam coal market, little further discussion of metallurgical coal markets will be included in this paper.

Steam coal is the largest segment of the coal industry, and electric power plants are the largest consumers of steam coal, accounting for some 68 percent of total coal consumption in 1976. Lesser amounts of steam coal are used by industry for process steam, space heating, and self-generation of electricity. Other uses are minor and are expected to essentially disappear in the future. Potentially, the largest user of steam coal in the future will be coal-based synthetic fuel plants. However, because of technical, economic, and financial problems, it now appears that coal gasification and coal liquefaction will not be a significant factor in the market until 1990 or later.

Traditionally, the utility and industrial coal markets have been strongly regionalized because of the limitations of transportation costs, and consumers have tended to buy coal from the nearest coal supply areas. The "shape" of the market was determined by the delivered cost of various coals vis-a-vis the delivered cost of other coals and other fuels. This regionalization of the markets has been broken down to some extent by the new air pollution control regulations for power plants, which have forced utilities to use more distant "compliance coals" rather than local high-sulfur coals. As a result, large tonnages of Western compliance coals have been moving east into the Upper Midwest markets at the expense of previously used Illinois Basin coals. In an attempt to slow down this movement and to restore the use of "Eastern" coals, the Carter Administration has proposed a policy in which scrubbers would be mandated on all new power plants regardless of the sulfur content of the coal burned.

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*"Compliance coal" is used here to designate any coal whose sulfur content is sufficiently low so that it can be burned without a scrubber and still be in compliance with the 1.2-pound of SO_2/MM Btu standard.

Anthracite coal production is mostly limited to the northeastern part of the State of Pennsylvania. At one time, it was mined in significant quantities and supplied a large share of the energy market in the Northeast. However, high mining costs combined with competition from cheaper oil and gas have resulted in this industry's shrinking to a mere shadow of its former self. At present, anthracite accounts for less than 1.0 percent of the total U.S. coal production. However, this coal does possess several advantages. It is well situated to serve the populous Northeast energy markets and it is a high-Btu, low-sulfur fuel. As a result, FEA has recently established a task force to assess the feasibility of increasing the use of anthracite in the future.

Among the steam coals, lignites play a special, more restricted role. Although the United States has vast reserves of lignite which can generally be mined at low cost, the low heat value (6,000-7,000 Btu per pound) and high moisture content of the lignites tend to restrict their use to markets near the lignite deposits. With few exceptions, lignite is utilized at mine-mouth locations for electric power generation. At present, the bulk of the lignite produced in the United States is mined in the states of North Dakota and Texas. While the use of such local lignites reduces the demand for coals in more distant supply areas, the converse is not true, because lignite cannot compete in distant markets.

In the case of bituminous and subbituminous coals, the product is sufficiently high in quality that long distance movements of such coal are competitive under certain conditions. However, in most cases the markets for these coals are strongly regionalized. It is useful to discuss the markets for these coals in terms of the main coal supply regions--Appalachia, the Illinois Basin, and the "West." The West, in turn, contains a number of subregions, each of which serves its own markets.

The great bulk of the new expansion in coal production in the United States through 1985 will occur in the West, especially in the Powder River Basin of Wyoming. It is important to discuss this expansion, because there is a great deal of confusion about this development. The demand for this Western coal arises from three distinct markets, each of which is controlled by different economic variables. The first market demand for Western coal is from utilities and industries located in the Western coal supply areas to meet local demands for energy.

The second market demand is for Western coal to serve utilities and industries located in the West but outside of the coal-producing areas. This market will be served both by coal used in mine-mouth power plants whose electrical output is "wheeled" to distant market centers and by coal which is transported to distant markets by train, barge, and/or slurry pipelines. This new demand for Western coal is primarily stimulated by the shortfall in natural gas supplies, which is causing utilities and large industrial energy users in the West (especially in the West South Central Region) to build new coal-fired plants to replace their old gas-fired plants.

The third market demand is the so-called "compliance coal" market. This market is stimulated by the desire of utilities (mainly in the Upper Midwest) to avoid the installation of expensive flue gas desulfurization units ("scrubbers"), which would be required if they continued to use high- and medium-sulfur coals from the Midwest. These utilities and industries, in some cases, are paying a considerable premium over the cost of local coals in order to purchase low-sulfur (compliance) coals from the West or from Appalachia. The impact of this penetration has been most severe on the market for Illinois Basin coals.

Future Coal Demand

Table 1 indicates our forecast of the total demand for coal in 1985 by major consuming sectors. You will note that we are more optimistic than the Carter Administration regarding the demand for utility coal, but much less sanguine in regard to industrial demand. For the sake of comparison, we have also included the forecasts prepared by Joel Price of Dean Witter and by Island Creek Coal Company. The key point to note is the consensus that the Carter Administration is too optimistic, and that it is unlikely that U.S. coal production will reach 1.27 billion tons by 1985.

Table 2 indicates the trends in the demand for coal by electric utilities through 1985. These data indicate estimated coal demands by NERC region. The boundaries of the NERC regions are shown in Figure 1. Although the overall growth rate of 7.3 percent per year may appear to be high, we feel that it is reasonable because the phase-out of natural gas as boiler fuel, and the delays in bringing new nuclear plants on stream will force utilities to rely heavily on coal for their future fuel supplies. The very high growth in the Southwest regions of ERCOT and SPP is mostly a response to the phasing out of extensive gas-fired capacity.

Despite the rapid growth in utility coal use in the West, from 89 million tons in 1976 to 337 million tons in 1985, some 59 percent (488 million tons) of the total coal used by utilities in 1985 will still be consumed east of the Mississippi River. Secondly, although there has been much talk about Western coal being used in the East, only about 56 million tons, or 11.5 percent, of the 1985 coal supply for Eastern utilities will be Western coal. Therefore, more than 85 percent of the coal expansion in the West is expected to serve Western markets.

The future demand for coal by industry is very difficult to predict because of the great uncertainty which exists regarding the Federal Government's policies on coal use and environmental regulations. However, if we assume that the long-term switch away from coal can be reversed, and that part of the new energy demands by industry can be captured by coal, then we estimate that the potential regional demand for industrial coal in 1985 could be as shown in Table 3. The boundaries of the regions used in Table 3 are indicated in Figure 2. Under either scenario, the bulk of the future industrial coal usage is expected to occur in only two regions: the Midwest and the Southwest.

Table 1

COMPARISON OF UNITED STATES COAL DEMAND PROJECTIONS FOR 1985
BY MAJOR CONSUMING SECTORS

(Million Tons)

CONSUMING SECTORS	AMAX COAL (1)	ISLAND CREEK (2)	DEAN WITTER (3)	CARTER ADMINISTRATION (4)
Electric Utilities	824	744	778	779
Metallurgical	110	100	110	105
Industrial	107-154	90	104-134	278
Export	92	90	87	90
Synthetics	-	-	-	12
Other				1
TOTAL	1133-1180	1024	1080*-1110*	1265

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(1) AMAX Coal Company, Market Research Department, July 1977.

(2) Barker, Stonie, Jr., February 8, 1977, "Coal - Current Status and Future Prospects", speech before the Washington Society of Investment Analysts, Washington, D.C.

(3) Price, Joel, June 15, 1977, "The Supply and Demand for Steam Coal: Implications and Challenges", an address before the Richmond Society of Security Analysts, Richmond, Virginia.

(4) Executive Office of the President, Energy Policy and Planning, June 2, 1977, Replacing Oil and Gas With Coal and Other Fuels In The Industrial and Utility Sectors, page III-2.

* Does not add due to independent rounding.

Table 2

UTILITY COAL DEMAND, BY NERC REGIONS*

(Million Tons)

NERC Region	1976	1980	1985	Annual Percent Growth, 1976-85
ECAR	142.2	166.6	207.4	+ 4.3
ERCOT	12.0	39.9	69.3	+21.5
MAAC	32.8	38.6	40.3	+ 2.3
MAIN	57.3	73.4	86.1	+ 4.6
MARCA	28.4	45.9	66.9	+10.0
NPCC	7.8	10.1	13.8	+ 6.5
SERC	104.3	117.5	139.9	+ 3.3
SPP	9.1	48.3	101.4	+30.7
WSCC	39.9	70.7	98.9	+10.6
TOTAL	433.8	611.0	824.0	+ 7.3

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* See Figure 1 for regional boundaries.

SOURCE: National Electric Reliability Council, 1977
Preliminary data.

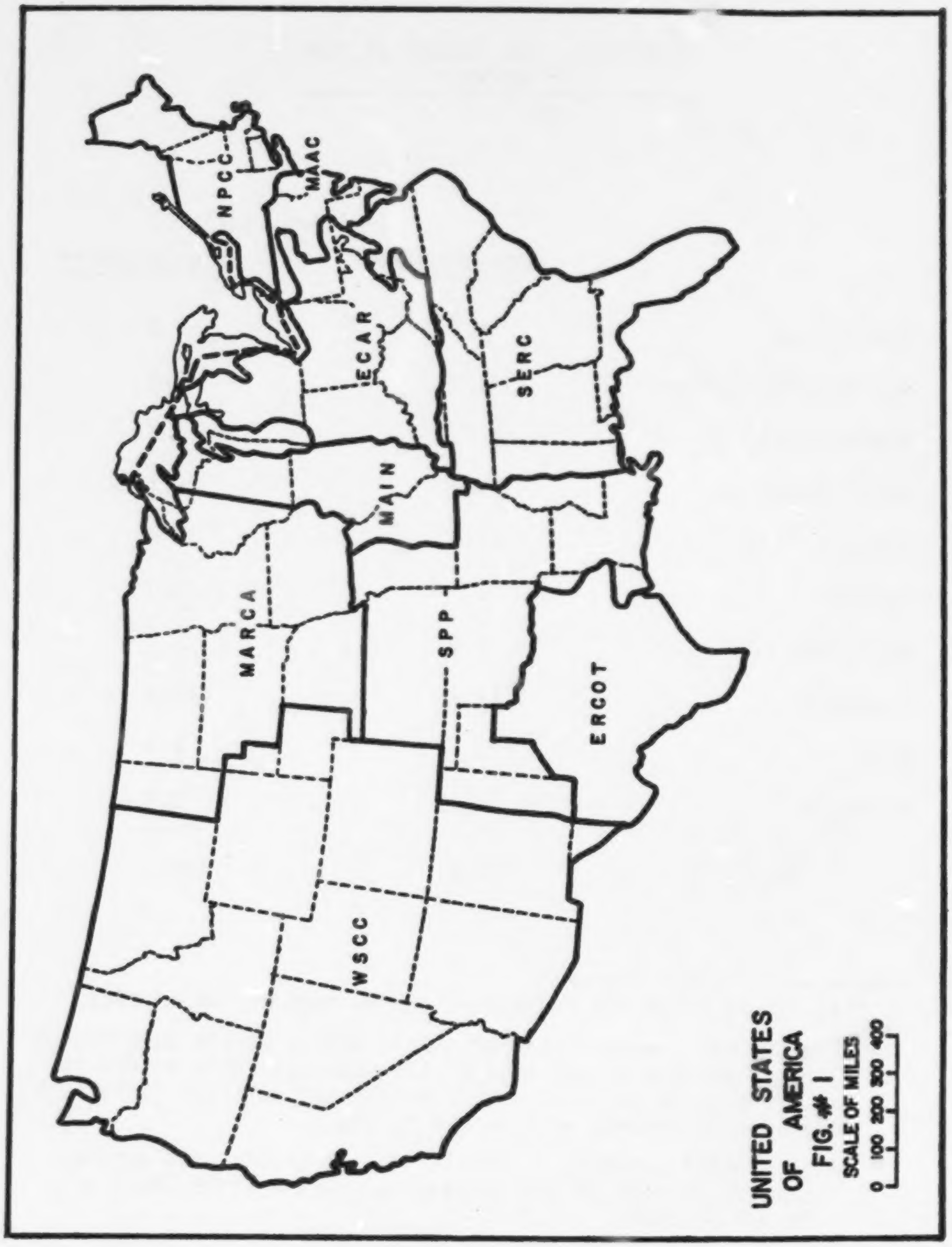
NPCC
MAAC
ECAR
SERC
MAIN
MARCA
SPP
ERCOT
WSCC
UNITED STATES
OF AMERICA
FIG. # 1
SCALE OF MILES
0 100 200 300 400

FIG. # 1 - BOUNDARIES OF NATIONAL ELECTRIC RELIABILITY COUNCIL REGIONS

Table 3

INDUSTRIAL COAL DEMAND IN 1985 BY REGIONS*

	(Million Tons) LOW GROWTH**	HIGH GROWTH***
New England	0.7	1.3
New York/New Jersey	3.6	4.8
Mid-Atlantic	15.9	18.5
South Atlantic	13.4	18.1
Midwest	31.6	38.7
Central	4.7	5.9
North Central	4.4	6.2
Southwest	25.6	49.0
West	4.1	7.7
Northwest	2.6	3.9
Total	106.6	154.1

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*See Figure 2 for FEA industrial energy regional boundaries.

**"Low Growth" scenario assumed that industry within each region will continue to use coal at the same rate that it did in 1975 plus 10 percent of the incremental increase (1975-1985) in energy demands will be met by coal.

***"High Growth" scenario is similar to low growth, but assumes that 20 percent of the incremental demand (1975-1985) will be met by coal.

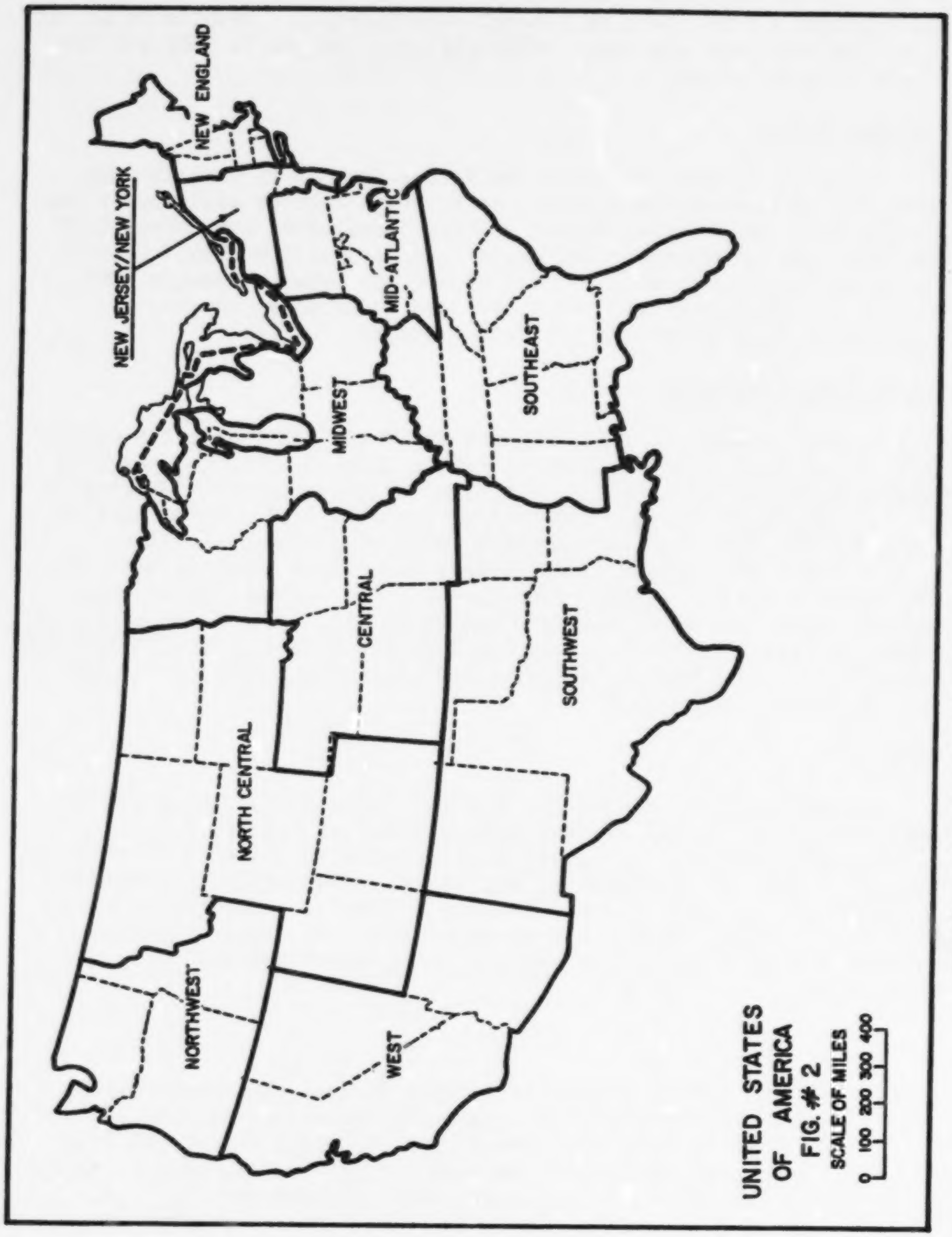
NEW ENGLAND
NEW JERSEY/NEW YORK
MID-ATLANTIC
MIDWEST
SOUTHEAST
CENTRAL
SOUTHWEST
NORTH CENTRAL
NORTHWEST
WEST
UNITED STATES OF AMERICA
FIG. # 2
SCALE OF MILES
0 100 200 300 400

FIG. # 2 - BOUNDARIES OF FEA INDUSTRIAL ENERGY DEMAND REGIONS

However, it should be noted that depending on the regional availability of natural gas and future pricing policies of the Federal Government, the regional shares could be altered significantly. Despite this, it is our opinion that the total industrial coal demand in 1985 will be in the forecast range.

Regional Demand

Now that we have estimated the future demand for coal through 1985, let us examine the question as to which regions will supply the coal to meet the forecast demand. Table 4 indicates our forecast of the 1985 coal demand by market sector and by supply region. Despite the large increase in Western coal production between now and 1985, Eastern and Midwestern coals are expected to continue to play a significant role in meeting our future demands for coal.

Supply/Demand Balances

Recent research by AMAX Coal has indicated that while the overall coal industry is expected to have surplus capacity through the early 1980's, potential shortfalls* in steam coal capacity could develop in the Illinois Basin by 1979 and in Appalachia by 1981. While part of the potential shortfalls in the East could be filled by surplus Western coal, this option is not likely to offer a total solution to the supply problem. Lastly, because there are a number of environmental, legal, and technical problems which might reduce the effective supply of Western coal by as much as 50 million tons or more below the currently forecast levels, the "surplus" capacity projected for the West may never materialize.

Summary

If public policy conflicts regarding the mining, transportation, and utilization of coal are not quickly resolved, coal's future role will be diminished and our dependence on imported oil will continue to increase. Many of the problems and uncertainties which face the coal industry are the result of our failure to develop a consistent set of policies for coal. Melvin Laird, in an excellent little pamphlet entitled Energy - A Crisis In Public Policy makes the following observation:

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*Note: These potential shortfalls were derived by the difference between the estimated demand and the projected supply (which is equal to current capacity minus depletions plus announced capacity). Because the data on new mine capacity in the 1981-1985 period are less complete for the East, there is a tendency to underestimate actual supply. The projected shortfalls should be taken as indicators of the regions in which there is a potential demand for additional mine capacity.

Table 4

COAL DEMAND IN 1985 BY MARKET AND SUPPLY REGION

(Million Tons)

SECTOR/MARKET	SUPPLY REGION					
	APPALACHIA	ILLINOIS BASIN	TEXAS LIGNITE	NORTH DAKOTA LIGNITE	WESTERN COAL	TOTAL
Electric Utilities	285	152	56	23	308	824
Industrial*	52-65	18-23	13-26	1-2	23-38	107-154
Metallurgical Coal	97	5	-	-	8	110
Exports**						
-- Metallurgical Coal	76	-	-	-	-	76
-- Steam Coal	16	-	-	-	-	16
Total	526-539	175-180	69-82	24-25	339-354	1133-1180

* Includes minor usage by commercial and retail customers.

** All exports allocated to Appalachia as exports from other regions have been small and irregular.

> "The failure of the Federal Government to come to grips with the crucial environmental/energy trade-offs is partially attributable to the fact that, in the Congress as well as in the executive branch, policy direction for energy and environment is treated separately. With missionary zeal, those in government dealing with each set of issues push their own programs toward conclusions that are often contradictory and sometimes actually impossible of resolution by the decisionmaker in the private sector, at the end of the regulatory chain."*

We, in the coal industry, are ready and willing to do our part in solving the energy problem. However, unless many of the policy roadblocks are resolved quickly, it will be very difficult, if not impossible, for coal to play as large a role in our future energy supply as is currently projected. Even under the most optimistic assumptions, it is questionable whether we will reach the Carter Administration's goal of almost 1.3 billion tons by 1985. Coal can be a part of the solution to the energy problem of the United States, but it is not a panacea.

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*Laird, M. R., 1977, Energy - A Crisis In Public Policy, American Enterprise Institute for Public Policy Research, Washington, D. C., p. 9.

WHERE DO WE GO FROM HERE IN R&D?

by

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ERDA is going into the Department of Energy on October 1, 1977. Figure 1 shows the projection of the major Fossil Energy activities (not including mining and coal preparation) for four years beyond FY '78. Once in the Department of Energy, we will have added to the program coal mining research and development and coal preparation work. The numbers for FY '78 are pretty firm, totaling a little over $600 million of new contract authority. The numbers for FY '79 and beyond are what the program managers are projecting as their needs for carrying out the program that has been initiated in the past and for the next fiscal year. That also includes some new starts that they believe they will be able to make as a result of research now underway. As you can see, it goes over a billion dollars per year in FY '80.

The chart shows a general breakdown of activities. Coal conversion includes gasification and liquefaction. Utilization means coal-oil slurry combustion, atmospheric and pressurized fluid-bed combustion, and direct combustion; as well as advanced high temperature turbines for use of coal-derived fuels. Advanced research and supporting technology means what it says with respect to research, but includes materials and component development work in support of the total program.

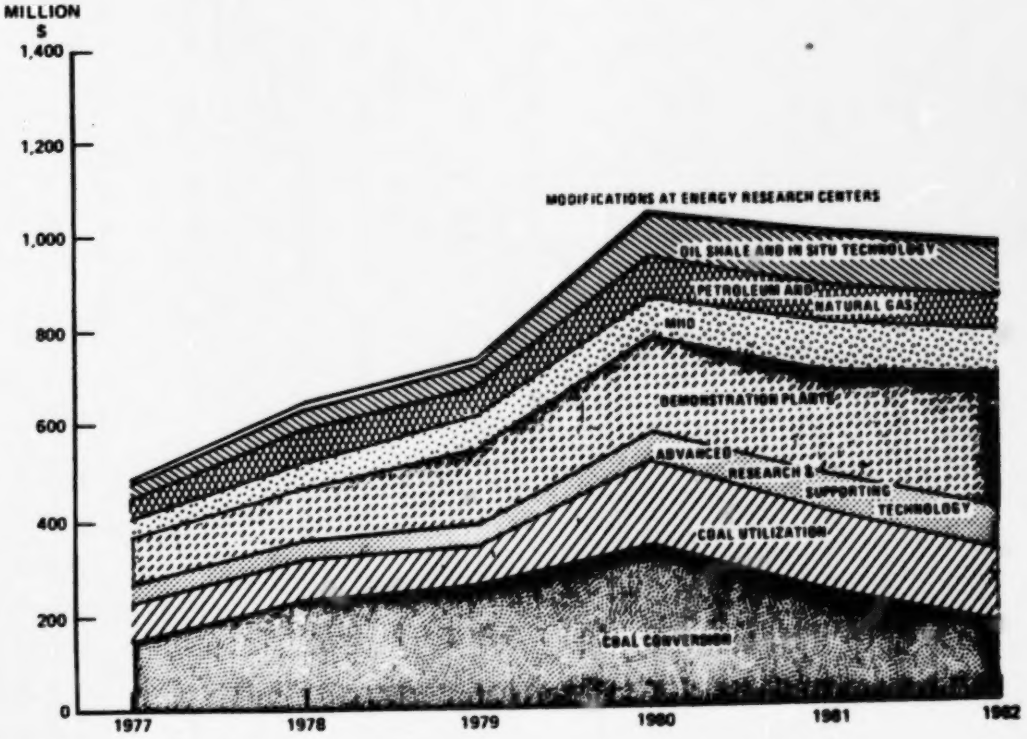
MHD is self-explanatory. Demonstration plants cover the large commercial scale projects we have under contract or are about to enter into contract. Petroleum, natural gas, and oil shale are not a subject of this Conference, but they are in the Fossil Energy Program of ERDA and they are likely to be in the program in the Department of Energy. It is a large program.

At this point in time, there are about 800 work efforts under contract in place around the world. I do not know how many subcontracts there are. There are the order of 200 contracts in universities alone on fairly basic studies. I believe our feeling, at the present time, is that the level of support in new or exploratory R&D has been limited by the number of ideas rather than by funds or other policy judgments. We are probably funding more than we ought, rather than the other way around.

The growth of the program has been very rapid. In FY '73, Fossil Energy's budget was the order of $50 million. Such rapid growth cannot take place without errors in judgment. In addition, some of our programs are in place by Congressional direction. This rate of growth of an R&D

FIGURE 1.

FOSSIL ENERGY OVERVIEW
BUDGET AUTHORITY DISTRIBUTION
BY MAJOR PROGRAM AREA
FY 1977-1982



activity is faster than is prudent when one thinks in terms of making wise investment decisions. However, the nature of the problem facing the country caused Congress to launch an accelerated activity with supplemental appropriations in FY '74, with the understanding that such an acceleration would bring with it more risk than had been the practice. When such an increase in obligational authority takes place, with pressure to obligate rapidly, you are forced to put under contract the best of what is available at that particular time. Once something substantial is under contract, jobs are at stake and it is difficult to stop.

Efforts are made to redirect and make projects more effective if it is determined that the original thrust is not as useful as it might have been. However, even though one finds that certain undertakings could be judged to have been mistakes from a Federal point of view, it may not be so. In the process, we train people; we improve the general knowledge base in fossil fuels; and, of course, we learn considerable about the behavior of components, materials, and chemistry of various unit operations involved in coal conversion and utilization.

So far as Fossil Energy's research, development and demonstration program in ERDA is concerned, we believe all of it supports the National Energy Plan with respect to improving the prospects and potential for increased use of coal, and making available as reserves, large resources of oil and gas in tar sands, bitumens and various tight formations. We do not see any breakthroughs coming and we do not see any results that indicate that getting coal, shale, tight formations, etc., is going to be inexpensive or simple. People fail to observe that we gave up extensive use of coal in many applications for good reasons. The world used considerable amounts of coal oil between whale oil and natural petroleum and stopped because natural petroleum is much easier. In addition, many parts of the world used coal-derived gas to operate cities--some until the late 1950's. Again, that was slowly phased out for good reasons. Natural gas is cleaner, easier, and less expensive. Now, we have a great deal of coal and we may go back to it. But, I think we should understand that the reason we go back is not because it is easy or inexpensive, but because it is the only choice we can see in front of us.

There are many people entering the research and development arena today who make the mistake of not looking into the history of coal use around the world. This, of course, has to be done carefully. If you look too hard at what has been done, then you fall into the trap of beginning to believe that there are no new ideas left to be found. That is not true. But, if one approaches R&D without looking at what has been done, then there is a great deal of time and effort wasted in reinventing the wheel. Coal is a very difficult material--every piece is different, even inches apart in the same seam. It has many constituents, including potential toxic substances which have not yet been regulated. Some products of coal are carcinogenic. The manufacture of coal-derived products has to be done with appropriate regard for the health and safety aspects of employees. While one can refine coal-derived liquids into specification-grade products that we are accustomed to dealing with, there is movement now to examine the impact of petroleum-derived liquids on health and safety. Regulations that would come from there would, of course, apply to coal liquids.

Today, one can purchase a license to operate coal liquefaction and gasification plants. They are very expensive and not competitive with alternative fuels. Atmospheric fluid-bed combustion appears to be coming along well. You probably will be able to buy one with commercial guaranties in the not-too-distant future, especially at the small industrial scale. Advanced power systems are also under development. Higher fuel costs will justify more complex technical systems to increase efficiency. The ideas involved really are not new, but the technology involved will require materials which do not now exist.

MHD is the Fossil Energy Program's long shot. It is an interesting approach for several reasons. One is that it offers the highest ultimate conversion efficiency when examined in terms of energy in coal to electricity off the busbar. The other reason has nothing to do with generation of electricity. To make MHD concepts work on coal, you must have a combustor up front that delivers products of combustion at the order of 4500°F. The present system seems to be favoring a one- or two-stage slagging combustor. If such combustors are actually made to function reliably, it will have a great deal of fallout in the development of coal gasifiers. MHD actually requires more severe service than coal gasification schemes under development. The MHD people are really out at the frontier of all the technology they are concerned with. They have had to think in terms of revolution in their concepts, rather than evolution. Even if only partial success is achieved in the MHD objective, the fallout will be substantial and beneficial to many applications. In addition, one has to inject and recover seed material. The recovery must take place at high temperature and, thus, extremely difficult hot gas cleanup conditions have to be dealt with. Again, if this sort of problem is solved in MHD, then it undoubtedly will have application to the other combined cycle operations involving cleanup of coal-derived gases. The ultimate configuration for coal-fired MHD that provides the maximum potential efficiency would be a three-cycle type of plant; that is, an MHD converter, some kind of gas turbine and a steam plant. This is a complex engineering system involving extraordinary operating conditions and being able to keep all parts operating at the same time for reasonable periods of time. This probably is one of the greatest engineering challenges facing fossil energy R&D.

We are just beginning to look at three liability and operating problems of such systems as advanced combined cycles. The Petroleum and Natural Gas Program has several thrusts. In the Enhanced Oil Recovery Program the objective is to be able to economically extract very large amounts of oil, in place, left behind after primary recovery has been completed. In the gas area, the principal thrust in either the Eastern or Western formations is to develop technology to economically exploit the large amounts of gas available in tight formations. What we mean here is a conventional well will not produce at a rate sufficient to make very useful recovery or investment possible. Fracturing or other techniques may raise production rates to where exploitation becomes attractive. In the gas area, we are essentially trying to convert a resource to a reserve. In the Eastern Devonian fields, there are considerable numbers of producing wells. These are usually in areas with extensive natural fracture patterns and, thus, have sufficiently high production rates. Another interesting characteristic of wells in Devonian fields is that they produce for very long periods of time, albeit at a lower rate. Many holes have been drilled in Devonian fields--in tens of thousands. Most of them have been declared dry holes. I think you are aware that, generally, if a hole is not a producer, it is written off as drilling expense. If one produces from a hole, then the hole must be capitalized. Many times it is not useful to produce from low-production rate holes because the investment recovery is too slow. It is conceivable that one could increase production in Devonian shales in a significant way by just not requiring capitalization of low producers.

Within Fossil Energy, we are estimating that gas from tight formations may be less expensive than gas from coal. However, until enough work is done, this will not be well understood.

Synthetic pipeline quality gas from coal will be the order of $3 or more per million Btu. Our lowest estimates are for processes that are in the development stage rather than for processes that are in the stage of commercial availability. Some of this low-potential cost of the more advanced processes may be real. On the other hand, as is often true, development of economics are attractive early in the development process because one has not yet fully developed their technology and come to grips with all the problems. We are estimating low-Btu gas to be the order of $2.30 a million Btu or thereabouts with technology that is currently available.

The major uncertainty is in the environmental area, but I do not think that this is a serious problem. It is mainly uncertainty because such units have not been operated under modern standards. There does not appear to be any unusual process requirements for cleanup of low-Btu gas processes. We have eight industrial or commercial low-Btu demonstrations under contract at the present time for various applications over a range of sizes using a variety of coals. It will almost all be operating in 1980. Assuming reasonable success, these ought to demonstrate the capability of this technology for meeting certain potential demands. If natural gas prices go in the direction people seem to think they are going in, these industrial low-Btu applications ought to be commercially attractive. Also, one can operate a low-Btu gasifier system to meet very tight environmental standards--tighter than is possible in a direct combustion application.

Liquefaction of coal seems to indicate a product at the order of $30 a barrel; shale liquids, the order of $20 a barrel. While these numbers sound high compared to world price of oil, they are not high in a functional way. Gasoline at 75¢ a gallon without taxes is really pretty interesting compared to walking. Of course, the economy is not adjusted to that sort of cost and people are not accustomed to thinking about it. People often ask why we have both a shale liquids program and a coal liquids program. They are different raw materials and produce products of different characteristics. Coal liquids are very aromatic. Shale liquids are not nearly so. The route to gasoline is probably through coal. The route to jet fuels and other distillates is probably through shale. One can produce either product from either source, but the economics are more attractive with a particular feedstock/end-product combination such as shale oil to distillate rather than shale oil to gasoline.

In addition, there is the Fischer-Tropsch process currently in operation in South Africa. If operated with high temperature entrained gasifiers, it is potentially a very clean process from an environmental point of view and, with development of more selective catalysts, capable of producing a wide range of hydrocarbon liquids.

At the present time, this looks to be the most expensive process. Again, perhaps we know most about it and, therefore, we have the most realistic number.

QUESTION: WHAT ABOUT THE ENERGY EFFICIENCY OF THE FISCHER-TROPSCH PROCESS?

ANSWER: It all depends on how you look at the process. Even in Fischer-Tropsch, if you try to make all one product (such as gasoline), the efficiency is probably 40 percent. However, coal does not really want to behave that way. Neither does shale. Most processes involving coal or shale are somewhat similar to processes for finding oil: You put something in, you heat it up and a range of products come out. If one can arrange a process that produces a useful product mix, even the Fischer-Tropsch process may be as much as 60 percent efficient.

Other liquefaction processes may be 70 percent efficient. While it may be easier in the early stages of building synthetic fuels industry to have a single-product plant, it is probably likely that large-scale commercialization would have multi-product plants.

QUESTION: WHAT ABOUT FLASH HYDROPYROLYSIS?

ANSWER: We are moving ahead rapidly with very rapid hydropyrolysis. The work on the West Coast with Rocketdyne is very encouraging--maybe because we have so little data. At this time, this process route seems to offer very high grade hydrocarbon products with potentially very large capacity per unit of investment in steel.

In general, as we have learned more about any process, it is surprising how the economics of all converge on something fairly high and not too far from existing technology. Look at a coal liquefaction or gasification plant of nearly any kind--the order of 30 percent to 40 percent of the product price is the coal feedstock. About 50 percent or so is the cost of money. The rest is other costs. R&D can make its biggest impact on decreasing the amount of capital required. Actually, if we could figure out a way to use the interest rate with our R&D funds, we would have a very high benefit/cost ratio. The capital charges become very small if one could go to a forty-year write-off and 3 percent money.

However, we have been doing many process evaluations trying to understand where the capital and operating costs are. The principal objective is to identify targets of opportunity for Federal research dollars.

CONCLUDING REMARKS:

I have tended to indicate the problems associated with coal conversion are very difficult. They are. It is not going to be inexpensive, simple or straightforward. However, research and development will help to make the plants more reliable, more easily operable, more environmentally acceptable and safer from an occupational health and safety point of view.